Department of Electrical Engineering and Automation

Demand Response Benefits for Major Assets of High Voltage Distribution Systems

Capacity Gain and Life Management

Muhammad Humayun

Aalto University

DOCTORAL
DISSERTATIONS

Aalto University publication series
DOCTORAL DISSERTATIONS 188/2015

Demand Response Benefits for Major Assets of High Voltage Distribution Systems

Capacity Gain and Life Management

Muhammad Humayun

A doctoral dissertation completed for the degree of Doctor of Science (Technology) to be defended, with the permission of the Aalto University School of Electrical Engineering, at a public examination held at the lecture hall S3 of the school on December 04, 2015 at 12:00 noon.

Aalto University
School of Electrical Engineering
Department of Electrical Engineering and Automation
Power Systems and High Voltage Engineering

Supervising professor
Professor Matti Lehtonen

Thesis advisor
Professor Matti Lehtonen

Preliminary examiners
Prof. Lothar Fickert, Graz University of Technology, Austria
Assoc. Prof. Patrik Hilber, KTH - Royal Institute of Technology, Sweden

Opponents
Prof. Lothar Fickert, Graz University of Technology, Austria
Prof. Jarmo Partanen, Lappeenranta University of Technology, Finland

Aalto University publication series
DOCTORAL DISSERTATIONS 188/2015

ISBN 978-952-60-6519-9 (printed)
ISBN 978-952-60-6520-5 (pdf)
ISSN-L 1799-4934
ISSN 1799-4934 (printed)
ISSN 1799-4942 (pdf)
http://urn.fi/URN:ISBN:978-952-60-6520-5

Unigrafia Oy
Helsinki 2015

Finland

NORDIC ECOLABEL
441 697
Printed matter

A? Aalto University

Aalto University, P.O. Box 11000, FI-00076 Aalto www.aalto.fi

Abstract

Author
Muhammad Humayun

Name of the doctoral dissertation
Demand Response Benefits for Major Assets of High Voltage Distribution Systems: Capacity Gain and Life Management

Publisher School of Electrical Engineering

Unit Department of Electrical Engineering and Automation

Series Aalto University publication series DOCTORAL DISSERTATIONS 188/2015

Field of research Power Systems and High Voltage Engineering

Manuscript submitted 16 July 2015 **Date of the defence** 4 December 2015

Permission to publish granted (date) 30 October 2015 **Language** English

☐ **Monograph** ☒ **Article dissertation (summary + original articles)**

Abstract

Power systems require an adequate capacity and higher utilization efficiency for an economic and reliable supply of electricity. However, their utilization efficiency is ordinary owing to low load factor and reserve capacity needs. Moreover, the growth of electricity demand and aging infrastructure call for massive investments in form of expansions and replacements. Therefore, the power industry is searching for novel solutions to deal with the future needs. Demand response (DR), a load shaping tool in smart grids, can be a potential solution to the future needs.

The aim of the dissertation is to assess the DR benefits of capacity utilization gain and better life management for major assets of high voltage grid. The study focuses on subtransmission grids because they have captured least attention in the prior research. Primary substation transformers have given special attention here due to their vital position in the system and high component cost. The aim of the dissertation is further divided into three tasks in order to distinguish the DR benefit among phases of operations and planning and various components. The first task proposes optimization models for utilization gain and life management of transformers by DR during normal and contingency operations. The second task offers tools for optimal capacity planning of transformers in primary distribution substations with and without considering DR. These tools incorporate all transformer related costs, their failure rate increase with age, and their salvage value based on loss-of-life. The third task determines the potential of DR in mitigating the redundancy needs of lines/cables, transformers, and busbars by comparing outage cost due to their contingencies.

The simulations are performed using the developed models for typical Finnish systems. The results indicate the following notable deductions. The utilization efficiency of grid components can be substantially improved using DR that depends upon load shape and its DR capability. Also, DR offers significant better life management potential for transformers during both normal and contingency operations. Moreover, the employment of DR along with remote switching of load transfer between substations provides superior savings in transformer capacity planning as compared to that of manual load shifting. Furthermore, the optimal decisions of DR activations are essential in order to gain the intended DR benefits at a minimal expense.

The power system utilities can use the models of this dissertation for making decisions of DR deployments. These deployments will be helpful in delaying or eliminating the capacity investments. Moreover, the tools of the second task will help asset managers for taking optimal planning decisions of transformer ratings and their replacement and maintenance schedules.

Keywords Demand response, high voltage grid, transformers, aging, asset utilization, contingency, redundancy, smart grids.

ISBN (printed) 978-952-60-6519-9 **ISBN (pdf)** 978-952-60-6520-5

ISSN-L 1799-4934 **ISSN (printed)** 1799-4934 **ISSN (pdf)** 1799-4942

Location of publisher Helsinki **Location of printing** Helsinki **Year** 2015

Pages 202 **urn** http://urn.fi/URN:ISBN:978-952-60-6520-5

Aalto-yliopisto

Aalto-yliopisto, PL 11000, 00076 Aalto www.aalto.fi

Tiivistelmä

Tekijä
Muhammad Humayun

Väitöskirjan nimi
Demand Response Benefits for Major Assets of High Voltage Distribution Systems: Capacity Gain and Life Management

Julkaisija Sähkötekniikan korkeakoulu

Yksikkö Department of Electrical Engineering and Automation

Sarja Aalto University publication series DOCTORAL DISSERTATIONS 188/2015

Tutkimusala Power Systems and High Voltage Engineering

Käsikirjoituksen pvm 16.07.2015 **Väitöspäivä** 04.12.2015

Julkaisuluvan myöntämispäivä 30.10.2015 **Kieli** Englanti

☐ **Monografia** ☒ **Yhdistelmäväitöskirja (yhteenveto-osa + erillisartikkelit)**

Tiivistelmä

Voimajärjestelmät tarvitsevat riittävästi kapasiteettia ja korkean käyttöasteen taatakseen taloudellisen ja luotettavan sähkön saannin. Järjestelmän potentiaalia ei saada kuitenkaan hyödynnettyä täydellisesti matalan käyttökertoimen ja reservivaatimusten takia, minkä lisäksi kasvava sähkön kysyntä ja ikääntyvä järjestelmä lisäävät painetta investointeihin. Tämän takia sähköteollisuus on kiinnostunut uusista ratkaisuista, joilla järjestelmäresurssit saadaan tehokkaampaan käyttöön. Älykkäiden sähköverkkojen tarjoama kysyntäjousto (demand response, DR) nähdään yhtenä tällaisena ratkaisuna.

Tämän väitöskirjan tarkoituksena on tutkia kysyntäjouston hyötyä siirtoverkon kapasiteetin hyödyntämisessä sekä eliniän hallinnassa. Työ keskittyy suurjännitejakeluverkkoon, jonka osalta aihetta ei ole vielä juuri tutkittu. Erityisesti keskitytään muuntajiin niiden tärkeyden ja korkean kustannuksen takia. Jotta kysyntäjouston tarjoama hyöty voidaan erotella tarkemmin verkon eri toimintojen, suunnittelun ja komponenttien kesken, väitöskirja on jaettu kolmeen osaan. Ensimmäinen osa esittelee optimointimallin muuntajan käyttöasteen parantamiseen ja eliniän pidentämiseen kysyntäjouston avulla normaalikäytön aikana sekä vikatilanteissa. Toinen osa tarjoaa työkaluja muuntajan optimaalisen kapasiteetin mitoittamiseen kysyntäjouston kanssa ja ilman. Kolmannessa osassa tutkitaan kysyntäjouston potentiaalia vähentää järjestelmän ylimitoittamista vertailemalla keskeytyskustannuksia.

Työssä suoritettavat simuloinnit tehdään Suomen järjestelmää kuvaavalla mallilla. Tulokset osoittavat, että verkostokomponenttien hyödyntämistä voidaan tehostaa huomattavasti kysyntäjoustolla riippuen kuormituksen vaihtelusta ja sen tarjoamasta joustosta. Kysyntäjousto vähentää myös huomattavasti muuntajien vanhenemista normaalin käytön ja vikatilanteiden aikana. Kysyntäjousto optimaalinen aktivointi on kuitenkin olennaista, jotta halutut hyödyt voidaan saavuttaa.
Järjestelmävastaavat voivat käyttää työssä esiteltyjä malleja, jos he suunnittelevat kysyntäjouston hyödyntämistä esimerkiksi investointipäätösten yhteydessä. Lisäksi työn toisessa osassa esiteltävät työkalut auttavat suunnittelijoita muuntajien optimaalisessa mitoittamisessa ja ylläpidossa.

Avainsanat Demand response, high voltage grid, transformers, aging, asset utilization, contingency, redundancy, smart grids.

ISBN (painettu) 978-952-60-6519-9 **ISBN (pdf)** 978-952-60-6520-5

ISSN-L 1799-4934 **ISSN (painettu)** 1799-4934 **ISSN (pdf)** 1799-4942

Julkaisupaikka Helsinki **Painopaikka** Helsinki **Vuosi** 2015

Sivumäärä 202 **urn** http://urn.fi/URN:ISBN:978-952-60-6520-5

Acknowledgements

Praise be to Allah, Most Gracious, Most Merciful. This dissertation presents the final results of my work as a doctoral candidate at the Department of Electrical Engineering and Automation, Aalto University, Finland, since September 2012. The funding support for the dissertation was provided in parts through projects SGEM (Smart Grids and Energy Markets), SAGA (Smart Control Architecture for Smart Grids), and FLEXe (Flexible Energy System).

First of all, I would like to express my deepest gratitude to my supervisor, Professor Matti Lehtonen, for continuous guidance, invaluable advices, co-operative supervision, insightful discussions, and valuable feedbacks. Thank you for showing the confidence in me during difficult times, listening to my ideas and arguments, and providing me freedom to realize my own direction of work. Your welcoming attitude and great sense of humor always had a calming impact.

I wish to express my particular gratitude to my co-authors, colleagues, and friends Dr. Amir Safdarian and Dr. Merkebu Zenebe Degefa for guiding me through the process of converting an idea into a publication. Your prompt and detailed feedback on my proposals and written pieces were vital for me to complete the work in a quick time. Moreover, discussions with you on various topics of life were very interesting.

I wish to thank Professor Mahmud Fotuhi-Firuzabad for providing me feedback on my ideas during his short visits at Aalto University. I would also like to express my sincere gratitude to Mr. Ali Mubbashir for sharing ingenious thoughts and rendering fair and constructive criticism in numerous situations. I am thankful to Mr. Antti Alahäivälä for translating the abstract of this dissertation in the Finnish language.

I wish to give special thanks to Mrs. Meri Lundahl for introducing me to effective life management techniques in the beginning of my doctoral study. My personality trait transition from a passive to an active was only possible after taking coaching sessions from you. I also wish to thank Mr. Hammad Kabir for helping me during this transition by offering me positive energy during intense conversations over lunches.

A particular thanks to Dr. Muhammad Shafiq and Dr. Muhammad Usman Sheikh for sharing jokes and providing the opportunities of quality fun time. I am grateful to my colleagues and friends Mr. Amjad Hussain, Mr. Farhan Mahmood, Mr. Bruno Sousa, Dr. John Millar, Mr. Farhan Malik, Mr. Inam-ullah, and Mr. Osama Khurshid for friendly working and living environment. To my colleagues and friends, I could not name you all, but I wish to tell that acquainting with you all will continue to hold a special place in my memory.

I would like to express my greatest and warmest thanks to my parents and siblings, Shawana Kausar, Sarah Muzammil, Waheed Irshad, Iram Asim, Raheel Ahmed, Muhammad Babur, Ali Aamar, and Bhabies, without your support this journey would not have been possible. Thank you for your kindness, love, support, and encouragements. I hope to able to return it in years to come.

Finally, I am profoundly thankful to my beloved wife Sundis Humayun for her love, encouragements, assistance, patience, and smiles during writing of the dissertation.

Espoo, July 16, 2015,

Muhammad Humayun

Dedication

To my parents, Mr. Muhammad Irshad Ali and Mrs. Munawar Sultana.

Your unconditional love, sincere prayers, steady support, valuable advices, useful health tips, and continuous follow up on my thesis progress were vital for the success in this endeavor.

List of Publications

This dissertation consists of an overview and of the following six publications which are referred to in the text by their Roman numerals.

I. **M. Humayun**, M. Z. Degefa, A. Safdarian, and M. Lehtonen, ''Utilization improvement of transformers using demand response,'' *IEEE Transactions on Power Delivery*, vol. 30, no. 1, pp. 202-210, Feb. 2015.

II. **M. Humayun**, A. Safdarian, M. Z. Degefa, and M. Lehtonen, ''Demand response for operational life extension and efficient capacity utilization of power transformers during contingencies,'' *IEEE Transactions on Power Systems*, vol. 30, no. 4, pp. 2160-2169, Jul. 2015.

III. **M. Humayun**, M. Ali, A. Safdarian, M. Z. Degefa, and M. Lehtonen, ''Optimal use of demand response for lifesaving and efficient capacity utilization of power transformers during contingencies,'' *IEEE PES General Meeting July 26-30, 2015, Denver, CO, USA*.

IV. **M. Humayun**, B. J. O. Sousa, A. Safdarian, M. Ali, M. Z. Degefa, M. Lehtonen, and M. Fotuhi-Firuzabad, ''Optimal capacity management of substation transformers over long-run, '' *IEEE Transactions on Power Systems*, acceptance notification received in Jan. 2015.

V. **M. Humayun**, A. Safdarian, M. Ali, M. Z. Degefa, and M. Lehtonen, ''Optimal capacity management of substation transformers by demand response combined with network automation, '' *Electric Power Systems Research*, submitted for review in Aug. 2015.

VI. **M. Humayun**, B. J. O. Sousa, M. Z. Degefa, S. Kazemi, and M. Lehtonen, ''Markov model based assessment for redundancy mitigation in high voltage grids using demand response,'' *International Review of Electrical Engineering*, vol. 8, no. 4, pp. 1349-1362, Jul.-Aug. 2013.

Author's Contribution

The author of this thesis is the main contributor to all the publications [I]–[VI]. The author had the lead role in all the manuscripts and was responsible for developing the concepts, performing the simulations, analyzing the results, and writing the papers. The contributions from the co-authors are indicated in the following paragraphs.

Publication [I]:

Utilization improvement of transformers using demand response

M. Z. Degefa provided the test network details and performed the load disaggregation in Section IV. The organization of this publication and presentation of the results were improved based on the comments from A. Safdarian. M. Lehtonen supervised the work.

Publication [II]:

Demand response for operational life extension and efficient capacity utilization of power transformers during contingencies

A. Safdarian contributed in this publication by encouraging the addition of an optimization function in the algorithm of Section III and by remarks on the structure of the whole article. M. Z. Degefa carried out the load disaggregation in Section IV and suggested the Case 2 in Section V. This publication was supervised by M. Lehtonen.

Publication [III]:

Optimal use of demand response for lifesaving and efficient capacity utilization of power transformers during contingencies

The co-authors of this article contributed in the manuscript through discussions and comments.

Publication [IV]:

Optimal capacity management of substation transformers over long-run

B. J. O. Sousa, M. Ali, and M. Z. Degefa contributed in this publication through discussion and comments on the initial draft and proposals on the revision. A. Safdarian helped with the feedback on the entire article and especially on Section II. M. Fotuhi-Firuzabad suggested some of the sensitivity studies in Section IV. This article was inspired and directed by M. Lehtonen.

Publication [V]:

Optimal capacity management of substation transformers by demand response combined with network automation

The feedback from second, third, and fourth author was useful in improving the text and structure of the article. M. Lehtonen supervised the work and contributed by comments and discussions.

Publication [VI]:

Markov model based assessment for redundancy mitigation in high voltage grids using demand response

M. Lehtonen motivated and supervised the study. The load disaggregation by conditional demand analysis in Sections III.1 and VI.2 was explained and performed by M. Z. Degefa. S. Kazemi helped through discussions on reliability analysis methods. B. J. O. Sousa provided the valuable feedback on the written manuscript and organization of the text.

Table of Contents

List of Abbreviations

Abbreviations	Description
DR	Demand response
DTR	Dynamic thermal ratings
EV	Electric Vehicle/s
GAMS	General algebraic modelling system
HST	Hottest-spot-temperature
HV	High voltage
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
LC	Load curtailment
LOL	Loss-of-life
MV	Medium voltage
NSS	Neighboring substation/s
OFAF	Oil forced air forced
ONAF	Oil natural air forced
TOU	Time-of-use

List of Symbols

Symbol	Description
a, a'	Indices of year
$a_{j,LL}^{a}$	Binary variables
a_{uv}	Transition rate from state u to state v in a transition rate matrix
b	Binary decision variable representing transfer of load to a neighboring substation
$b_{i,j}^{a}$	Binary decision variables denoting the selection of a transformer as a replacement
c	Contingency index
c_{DR}	Unit incentive paid to customers for using their DR flexibility
c_{LC}	Unit load curtailment cost
c_{SW}	Cost of load shifting to a neighboring substation
d	Discount rate (based on inflation and interest rates)
$fb_{i,j}$	Binary decision variables denoting the selection of a particular transformer as initial transformer
h	Index of hour in a year
h_{sw}	Switch time, its value depends upon the type of load transfer (i.e., manual or remote) between substations
i	Index of transformer size
j, j'	Indices of transformer locations in a substation
m	Transformer cooling type dependent parameter
mc_{j}^{a}	Maintenance cost of transformer at location j and year a
n	Transformer cooling type dependent parameter
p_{LL}	Probability of load level LL
r	Number of states in a Markov model except Up state
r_{j}^{a}	Loss equivalent resistance of transformer on location j at year a
s	Index for states in a Markov model
t, t', t''	Indices of time intervals
t_{CB}	Circuit breaker switching time, including fault detection
t_{DR}	DR activation time
t_{req}	Time for which load is higher than capacity
t_{4}	Time required reaching state '4' from state '1' through state '3'
u	Index for the states in a Markov model
v	Index for the states in a Markov model
x	Load point index
y	Decrease in equivalent age of a transformer due to a maintenance action
z, z', z''	Indices of the hour in a year

A	Maximum value of planning years
Ag_j^a	Age of transformer at location j and year a
C_{DR}	Demand response capability of load (%)
C_i	Procurement cost of transformer size i
C_{Inv}^{ini}	Investment cost of initial transformer
C_{Inv}^{rep}	Investment cost of replacement transformer
C_j	Investment cost of the transformer at location j
$C_{j,ini}$	Investment cost of the initially selected transformer at location j
$Cap_{j',ini}$	Capacity of initial transformer at location j'
$Cap_{j',rep}$	Capacity of replacement transformer at location j'
CIC_1	Customer interruption cost parameter 1 (€/kW/fault)
CIC_2	Customer interruption cost parameter 2 (€/kWh)
D_{LL}	Duration of load level LL
$DR_{j,a,h}^{z}$	Linear variable for demand deferred
$DR_{j,a,h}^{z,z'}$	Linear variable for load deferred from hour z to later hour z'
$DR_{j,a,h}^{z'',z}$	Linear variable for load deferred to z in prior hours z'' (DR load recovery)
$ECOST$	Expected annual outage cost for the entire network
$ECOST_h$	Expected outage cost for faults at hour h
ER	Emergency rating multiplier of a transformer
F_{AA}	Aging acceleration factor
F_{EQA}	Equivalent aging factor
$I_{j,LL}^{a}$	Current of transformer at location j, load level LL, and year a
K_U	Ratio of ultimate to rated load
L	Load demand (kW)
L_{DR}	Decrease in load due to demand response
$L_{DR}^{t,t'}$	Linear variable representing load deferred from one time t to a later time t'
$L_{DR}^{t'',t}$	Linear variable for load deferred to t in prior times t''
$L_{LC}^{t}, LC_{j,a,h}^{z}$	Linear variables for amount of critical load curtailed
L_{LL}^{a}	Load of a substation at load level LL and year a
LL	Index for load levels
$LNS_{j,LL}^{a}$	Load not supplied for transformer failure at location j, load level LL, and year a
$LOL_{j,ini}^{a}$	Loss-of-life of initial transformer at location j and year a
$LOL_{j,rep}^{a}$	Loss-of-life of replacement transformer at location j and year a
NL_j^a	No-load loss of transformer on location j at year a
NSS^a	Neighboring substation capacity at year a
OD_x^u	Outage duration of load point x in state u
OF_x^u	Outage frequency of load point x in state u
OP_x^u	Outage power of load point x in state u
P	Probability matrix of a Markov model

P_C^t	Available critical load at time t
P_{DR}^t	Available flexible load at time t
$P_{DR}^{t,t'}$	Peak bound of linear variable for load deferred from time t to later time t'
$P_{DR}^{a,z,z'}$	Peak bound of linear variable for load deferred from hour z to later hour z'
$P_{Eng,LL}^a$	Energy price at load level *LL* and year a
$P_{j,a,h}^z$	Modified load profile after overload relieving actions
P_{NSS}	Neighboring substation load receiving capacity
P_{tot}^t	Modified load profile at time t after DR activation
$P_{tran}^{\max}$	Transformer maximum permitted load in per unit
P_{tran}^{NP}	Transformer nameplate rating
P_u	Steady state probability of a system in state u
PW^a	Present worth factor of costs at year a
PWC	Total present value of cost of transformers in a substation
PWC_{Int}^a	Present value of interruption/reliability cost at year a
PWC_{Inv}^a	Present worth of the investment cost at year a
PWC_{Loss}^a	Present worth of losses cost at year a
PWC_{Mai}^a	Present worth of maintenance cost at year a
PWC_{Sal}	Present worth of salvage value of investments
R	Load loss ratio
R_1, R_2, R_3, R_n	Reserve number 1, 2, 3, and n, respectively
SS1,SS2	Substation number 1 and 2
T_{DR}	Demand deferment time without interruption cost (h/day)
$T_{DR}^{\max}$	Maximum time for which a load can be deferred
T_{LC}	Load curtailment time
T_r	Repair time of a component
TEC_j^a	Emergency capacity of healthy transformers during a contingency of transformer at location j and year a
$TLOL_j$	Total accumulated loss-of-life of transformer existing at j by the end of the study period
$TLOL_{j,ini}$	Total accumulated loss-of-life of initial transformer at location j
$TLOL_{j,rep}$	Total accumulated loss-of-life of replacement transformer at location j
TM	Transition rate matrix of a Markov model
T1,T2,T3,T4	Transformer number 1, 2, 3, and 4, respectively
$VOLL$	Value of lost load
W_a	Annual load demand
$\beta_{i,j}^a$	Dependent binary variables
$\beta_j^a, \beta_{j'}^a$	Dependent binary variables; unity value indicates that replacement transformer are in service
$\gamma_{i,j}^a$	Dependent binary variables

$\gamma_j^a, \gamma_{j'}^a$	Dependent binary variables; unity value indicates that initial transformer are in service.
ε	Index of time
η_i	General symbol for parameters (of capacity, cost, resistance, and no-load of loss of transformer) of size i
$\eta_{j,ini}$	Parameters (capacity, cost, resistance, and no-load of loss) for initial transformers at location j
$\eta_{j,rep}$	Parameters (capacity, cost, resistance, and no-load of loss) for replacement transformers at location j
θ_A	Ambient temperature
θ_H	Winding hot-spot-temperature
θ_H	Hottest-spot-temperature peak bound
$\theta_{H,t}$	Linear variable for HST at time t
λ_c	Outage rate of a component
λ_j^a	Outage rate of a transformer at location j and year a
μ_{uv}	Transition rate from state u to v
ξ	Hours of operation of a transformer
τ_{TO}	Transformer oil time constant
τ_W	Transformer winding time constant
ϕ_j^a	Binary decision variables for refurbishment of transformer at location j and year a
ψ_v	Visit duration of state v in a Markov model
ω_v	Visit frequency of state v in a Markov model
Δt	Time interval
$\Delta\theta_H$	Winding hottest-spot rise over top-oil temperature
$\Delta\theta_{H,i}$	Initial hottest-spot rise over top-oil temperature
$\Delta\theta_{H,U}$	Ultimate hottest-spot rise over top-oil temperature
$\Delta\theta_{H,R}$	Hottest-spot temperature at rated load
$\Delta\theta_{TO}$	Top-oil rise over ambient temperature
$\Delta\theta_{TO,i}$	Initial top-oil rise over ambient temperature
$\Delta\theta_{TO,R}$	Top-oil temperature rise at rated load
$\Delta\theta_{TO,U}$	Ultimate top-oil rise over ambient temperature

1 Introduction

1.1 Background

High voltage (sub-transmission) networks provide the connection between transmission systems and medium voltage distribution systems. Their adequate capacity and high utilization efficiency are critical factors for a reliable and an economical delivery of electricity to the end use consumers [1]. However, their utilization efficiencies are ordinary due to low load factor and reserve capacity requirements to provide support during contingencies [2]. Approximately, a quarter of distribution assets are used only for 440 hours of peak load [3]. Furthermore, owing to the growing load and aging systems, the capacity of network components needs to be enhanced in response. The classical approach of capacity enhancement by installing new equipment is expensive, complex, lengthy, and may disturb the surrounding environment [4]. Therefore, innovative solutions are required for future networks to cope with the increased demand and aging infrastructure while maintaining the rational utilization efficiency [1]. In the last few years, several novel solutions have been proposed such as dynamic thermal ratings (DTR) with online condition monitoring, network reconfiguration, distributed generation, and demand response (DR) [2], [5] - [12]. In particular, DR has gained a tremendous attention in smart grid as it can be used as load shaping tool to achieve its potential benefits. Yet, prospective advantages of DR for high voltage distribution system components need further research. This dissertation puts an emphasis on the DR benefits of capacity and life management for the major assets of high voltage distribution system. This thorough study is necessary to compare the DR potential benefits with their required investment before making any real world implementation.

1.2 Objectives and Scope of the Dissertation

The objective of the dissertation is to assess the potential benefits of DR in utilization improvement and aging reduction in high voltage grid (subtransmission). The components considered in the analysis include primary substation (high-voltage/medium-voltage) transformers, lines/cables, and busbars. As primary substation transformers are the most critical and costly individual components and their contingencies results into acute and economic consequences [2], therefore, they are given a significant importance in the assessment.

The objective is further divided into tasks in order to distinguish the DR potential benefit among operational stages, planning phases, and components. The dissertation work consists of the following tasks:

Task 1: Assess the capacity and life time management benefits of DR for transformers during operational stages. Specifically, the subtasks include:

a) Develop an optimization model to quantify the benefits of DR in utilization improvement of transformers in normal operations (without considering contingencies) and its impact on aging. Then perform the simulation to obtain the results.
b) Develop a static rating limit based optimization model to estimate the potentials of DR for operational life extension and efficient capacity utilization of power transformers during contingencies. After that, demonstrate the impact of DR by simulation outcomes.
c) Develop a DTR limit based model for optimal use of DR for effective life management and capacity utilization of power transformers during contingencies. Afterwards, show the applicability of the model with the simulation of appropriate case studies.

Task 2: Evaluate the DR potentials in long-term capacity planning of substation power transformers. This task consists of the following subtasks:

a) Develop a planning tool for optimal capacity management of substation transformers over long-run and conduct simulations for various situations of transformer capacity planning encountered by utilities.
b) Modify the optimal transformer capacity planning tool of Task 2 (a) to include the DR and automation features and then quantify the benefits of DR through simulation results.

Task 3: Develop Markov models for evaluating the redundancy mitigation in high voltage grids using DR. Subsequently, assess the DR impact using the developed models.

In order to accomplish the objectives of the dissertation, at first DR capability of input load profile is determined by using a disaggregated load profile and identifying the flexible portion along with their duration of flexibility. Then, this data is utilized in the simulation of developed models in tasks that are mentioned in the beginning of this section. In each subtask, DR is assumed to be incentive based and it is activated to obtain the intended target. Afterwards, appropriate case studies are performed on typical Finnish systems. Finally, results are analyzed to report the findings.

1.3 Contributions of the Dissertation

This dissertation contains six publications [I] - [VI]. A brief overview of the major contributions in each publication is given in this section.

1.3.1 Demand Response Benefits for Transformers during Operations

The first three publications [I] - [III] discuss the capacity and life management benefits of DR for transformers during operational stages.

Publication [I] proposes a hottest-spot-temperature (HST) based optimization model to quantify the DR benefits for utilization efficiency improvement of transformers during normal operating conditions (without contingencies). The model aims to minimize the load deferrals under DR while maintaining the HST under a certain limit. This model is applied to a typical Finnish system for case studies of demand with and without DR. The results demonstrate that the capacity utilization of transformers can be significantly increased resulting into monetary benefits. Utilities can use this model for determining economically feasible zones where DR infrastructure investments should be made.

Publication [II] offers a novel optimization model to estimate the potentials of DR for operational life extension and efficient capacity utilization of power transformers during contingencies. The model selects combination of best remedial actions among DR, load curtailment (LC), and transferring load to a neighboring substation to relieve overload on healthy transformers during contingencies. The simulations are performed for typical Finnish substations based on the availability of DR and connection with the neighboring substation. The investigation of results depicts that the loss-of-life (LOL) of healthy transformers can be substantially reduced during contingency and utilization of transformers can be significantly improved. This model can be used by operators in selecting optimal combination of load relieving option during transformer contingencies. The level of loading increase during normal operation can also be determined by this work. Moreover, this study is useful in making DR investment decisions.

A universal optimization model is developed in [III] which is applicable for power transformers installed in all ambient conditions to obtain the optimal life management and effective capacity utilization benefits of DR. In this model, load relieving decisions for healthy transformers in a substation following contingencies are taken based on the HST thus resulting into optimal choices. The applicability of the model is validated by appropriate studies considering transformer contingencies in summer and winter seasons. By employing this model, the utilities need not to adjust transformer static ratings according to ambient conditions to obtain DR benefits towards lifesaving and utilization improvement.

1.3.2 Demand Response Benefits for Transformers during Planning

A tool for optimal capacity management of substation transformers is developed in [IV] and then DR and network automation features are added in the modified tool in [V].

In [IV], a new tool is developed for optimal planning of substation capacity over long-run. This tool contains an optimization model that considers the present worth costs of investment, losses, maintenance, reliability, and salvage value of transformers and provides the optimal selection and scheduling of multistage transformer installations and their refurbishments. The model incorporates the features of transformers' increase in failure rate with age and salvage value determination based on the actual LOL. The application of the tool is depicted by presenting various case studies representing the various situations encountered by utilities.

Publication [V] provides a novel planning tool for substation transformers capacity management with DR enabled load. In addition to DR and characteristics of [IV], load transfer to a neighboring substation (NSS) and associated switching types (i.e. manual or remote) has also been incorporated in this tool. Several case studies and sensitivity analyses are performed for typical Finnish substation capacity planning problems. The investigation of results obtained through this tool can help in deciding the DR employments.

1.3.3 Demand Response for Redundancy Mitigation in High Voltage Grid

The last publication [VI] investigates the potential of DR in mitigating the redundancy requirements of HV grid. The comparison of outage cost for future network is adopted as an assessment method; this comparison is between non-investment in the network and use of DR as redundancy alternative activated by network contingencies. In the presence of DR, novel Markov reliability models are developed in order to calculate the outage cost. The contingencies of lines, busbars, and transformers are considered in the assessment. The analysis conducted on a typical Finnish sub-transmission network indicates that the redundant capacity of the network proportional to DR capacity can be mitigated. Thus, significant investments can be avoided or delayed and network efficiencies can be improved using DR.

1.4 Dissertation Outline

The summary part of the dissertation begins with a brief Introduction (Chapter 1) on the dissertation subject covering background, objectives, and contributions. Chapter 2 contains the basics of DR and transformer thermal and aging fundamentals.

Chapter 3 deals with the capacity gain and lifesaving benefits of DR for transformers during operational stages [I] - [III]. These benefits are examined by developing optimization models and applying them in case studies for normal [I] and contingency operations [II], [III] in separate subsections.

Chapter 4 presents the design and application of tools for optimal capacity planning of substation transformers [IV], [V]. At first, a mathematical model is formulated for capacity planning of transformers over long-run [IV]. Then, DR and load transfer to NSS features are added in the modified planning tool [V]. The application of both the tools is also illustrated by appropriate case studies.

In Chapter 5, focus is on the redundancy mitigation of network components capacity using DR [VI]. Firstly, Markov models are developed for reliability analysis of HV grid. Afterwards, outage cost is compared for future networks between without DR and with DR enabled load. The obtained results for Finnish sub-transmission network are discussed in detail.

Chapter 6 provides the concluding remarks and possible future works.

Finally, the publications of the dissertation [I] - [VI] are attached in the Appendix.

2 Preliminaries

2.1 Introduction

This chapter provides the basic information of demand response (DR) and transformer thermal dynamics. The basics of DR include its definition, types, capability, benefits, and barriers. The methods of calculating transformer hottest-spot-temperature (HST) and aging are given in transformer preliminaries.

2.2 Demand Response

2.2.1 Demand Response Definition

A number of definitions have been used in the literature to describe the concept of DR; however, the following definition proposed by U. S. Department of Energy is the most popular and relevant.

"Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.'' [13]

According to the above definition, DR refers to the deliberate actions of electricity customers that lead to changes in their normal load profile. These changes in loads profile are required at critical periods when electricity procurement costs are very high or when reliability is compromised due to outage of critical components. The customers perform these changes to obtain monetary savings in their bills. These savings can be offered to them in form of reduced electricity prices or incentive payments.

2.2.2 Demand Response Types

DR programs are classified into two major categories; price-based and incentive-based [14]. This classification is based on the ways by which load changes are instigated. The following paragraphs provide the summary of these DR programs.

Price-based Demand Response Programs

Price-based DR programs are centered on dynamic pricing rates in which customers are charged with time-varying prices. These time-varying prices reflect the underlying costs of production and delivery. Customers modify their electricity usage according to the prices in order to reduce their electricity bills. These actions by customers also results into overall lower system cost. The most common price-based DR programs include Time-of-use (TOU) pricing, critical peak pricing, and real-time pricing.

By TOU pricing, different electricity prices are introduced in different periods of time. In its simplest form, it has two time periods; the peak and the off-peak. Electricity price at the peak period is set higher than that of the off-peak period. For example, a utility in Helsinki offers TOU tariff in which night prices are about 20% lower than that of day prices [15]. In critical peak pricing, pre-specified high electricity rates are superimposed over TOU or normal flat pricing for a short duration. The events of critical peak pricing are called during contingencies or high wholesale electricity prices for limited number of days or hours per annum. In real-time pricing scheme, customers are charged with hourly fluctuating prices that reflect the power system condition and real cost of electricity in wholesale market [16]. It is thought that real-time pricing is the most effective scheme for competitive electricity markets.

Incentive-based Demand Response Programs

Incentive-based DR programs offer monetary incentives to the customers for reducing their load in response to request signals. These programs are established by utilities, load serving entities, or regional grid operators to decrease load when grid reliability is jeopardized or when electricity prices are too high. The program administrators may penalize the enrolled customers that fail to fulfil their contractual commitments. The most common incentive-based demand response programs include direct load control, interruptible/curtailable rates, emergency demand response, and demand bidding/buyback.

In a direct load control program, the program operator can remotely control some customer devices on a short notice. Such programs have been commonly used to control water heaters and air conditioning devices in residential and small commercial areas. Interruptible/curtailable rates programs do not take the control of customer devices, however, contracted customers are bound to reduce the load on request to avoid penalty. In emergency demand response programs, customers receive incentive payments for reducing their load during emergencies conditions; however, these load reductions are voluntary. In demand bidding/buyback programs, customers bid for specific load reduction with associated cost in wholesale electricity markets. These load reductions are also obligatory for the selected bids.

2.2.3 Demand Response Capability

DR capability is the measure of possible energy that can be shifted over time. To assess the capability (available capacity) of DR, a number of studies and pilot projects around the globe have been performed [17] - [25]. As notified in [17], full deployment of advanced metering infrastructure in the US can reduce peak demand by 20% in 2019. In another study [18], it is estimated that technical potential of a summer peak demand reduction by DR is about 15.7% and expected share from residential, commercial, and industrial sectors is equal. Reference [19] stated that demand response in the U. K. is capable of reducing its peak demand by more than 15%. The estimated DR potential for the Nordic region is 21% of the peak demand [20]. Reference [20] also estimates the potential of demand response in Finland to be 20% of its peak demand. Based on a survey conducted in 2005, Finnish large scale industries have a technical DR potential of 9% of the peak load [21].

The focus of this thesis is the exploitation of DR capability benefit rather than its quantification, yet the input data of demand response capability is required. In order to determine the available DR capability of load at a particular time, information of following elements are needed; appliances existing at load side, their disaggregated load profile, and flexibility of each appliance. The method used to determine the DR capability of residential load in this dissertation is explained in the following paragraphs.

Domestic Appliances and their Demand Response Capability:

Based on flexibility in operation, domestic electrical appliances are classified into two categories: responsive and critical. The operation of responsive appliances can be shifted in time whereas critical appliances do not offer such a flexibility in operation. Washing machines and dishwashers can offer DR by delaying wash action and by changing cycle interval. DR in clothes dryers can be obtained by delaying its operation or by altering heating phase time. In cooling appliances (refrigerator and freezer), DR can be attained by postponing ice forming and defrost activities, modifying on-time cycle, and allowing slight temperature alterations during emergency times. Similarly, heaters and air conditioners can respond by rescheduling run time and by modifying temperature limits within the bounds set by users. The distinctive nature of heating loads, instigated by thermal inertia, makes them greatly responsive [26]. Table 2–I lists the DR time shifting capacity of controllable appliances [27] - [29] considered in this dissertation. Rest of all the devices are in the group of critical appliances.

TABLE 2-I

DEMAND RESPONSE POTENTIAL OF DOMESTIC APPLIANCES [27] - [29]

Appliance	DR Potential (Hours)
Refrigerator/Freezer/Air Conditioner / Clothes Dryer/Direct Space Heating	1
Storage Water Heater	3
Washing Machine	4
Storage Space Heating/Dish Washer	5

Load Disaggregation:

To obtain a disaggregated load profile, a one year automatic meter reading of hourly load data measured from 1600 residential customers in central Finland is used. A statistical regression technique (conditional demand analysis) is applied to this metered data, weather information, and statistical figures collected by survey [30]. The survey data comprises the information associated to houses, people living in them, and electrical appliances. The disaggregated load profile of a typical winter week-day for a typical house is shown in Fig. 2.1.

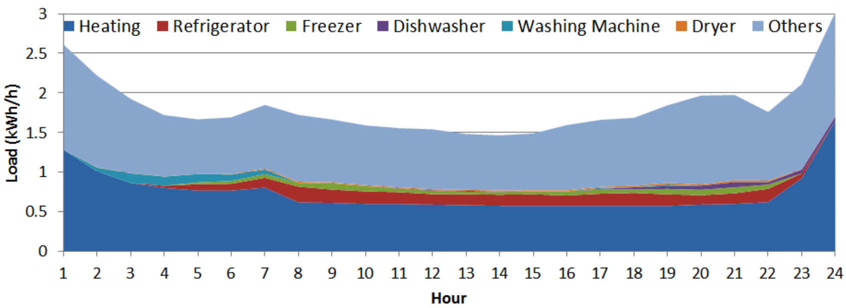

Fig. 2.1. Disaggregated load profile of a typical winter week-day for a typical house.

Finally, the average DR capability of load is determined by utilizing the disaggregated demand and DR values of appliances from Table 2–I.

2.2.4 Demand Response Benefits

The deployment of DR may provide significant technical, economic, and environmental benefits. The major benefits of demand response are briefly presented below:

Participants' Financial Benefits: Customers can decrease their electricity bills by shifting their load from higher price periods to lower price periods. They can also obtain bill savings through incentives by enrolling in various demand response programs. [31] - [33]

Improved System Utilization Efficiency: Customers' actions of shifting load from on-peak periods to off-peak periods produce relatively flatter load profile. This modified profile with lower peak results into overall higher utilization efficiency of power system infrastructure. The higher utilization efficiency can reduce the need of expensive expansions. [29], [34] - [35]

Reduction of Average Energy Price and Volatility: Decrease in peak load by DR lowers the costs of generation, transmission, and distribution. Thus, the average energy price reduces. It also reduces the price volatility by avoiding the use of expensive generators and relieving network limits at high demand. [13], [36] - [38]

Improved Reliability: DR improves the system reliability by acting as reserve capacity during contingencies and congestions. [39] - [42]

Market Power Mitigation: DR deters the abuse of market power of energy suppliers in situations of limited supplies or network constraints. [13]

Environmental Benefits: Peak reduction by DR mitigates the operation of high-polluting generation plants. Furthermore, demand response is also useful for the integration of intermittent renewables. [43] - [45]

2.2.5 Demand Response Barriers

Despite the significant recognized benefits of DR, it faces some barriers and difficulties in implementations [17], [46] - [47]. These barriers are related to technology and their cost, regulations, and knowledge. These barriers are briefly listed in below.

Technical Barriers

i. Lack of advanced metering infrastructure.
ii. High cost of some enabling technologies.
iii. Lack of standards for interoperability.
iv. Lack of automated load management system.

Regulatory Barriers

i. Lack of appropriate program design.
ii. Measurement and verification challenges.
iii. Lack of real time information sharing.
iv. Proper division of cost and benefits between various players.

Other Barriers

i. Lack of customer awareness related to potential opportunity.
ii. Confidentiality, privacy, and cyber security issues.

The efforts are being made to overcome these barriers by introducing new technologies, programs, regulations, and customer awareness campaigns.

2.3 Transformer Thermal and Aging Models

A transformer thermal model for calculating HST and aging equations are described in this section.

2.3.1 Thermal Model

The IEEE and IEC standards [48] - [49] give the following notions (1) - (5) for estimating the winding HST of transformers. It comprises of three elements; ambient temperature, top-oil rise over ambient temperature, and winding hottest-spot rise over top-oil temperature. All the temperatures are in °C.

$$\theta_H = \theta_A + \Delta\theta_{TO} + \Delta\theta_H \tag{1}$$

$$\Delta\theta_{TO} = (\Delta\theta_{TO,U} - \Delta\theta_{TO,i})(1 - \exp^{-\xi/\tau_{TO}}) + \Delta\theta_{TO,i} \tag{2}$$

$$\Delta\theta_H = (\Delta\theta_{H,U} - \Delta\theta_{H,i})(1 - \exp^{-\xi/\tau_w}) + \Delta\theta_{H,i} \tag{3}$$

$$\Delta\theta_{TO,U} = \Delta\theta_{TO,R}\left[{(K_U^2 R + 1)}\Big/{(R+1)}\right]^n \tag{4}$$

$$\Delta\theta_{H,U} = \Delta\theta_{H,R} K_U^{2m} \tag{5}$$

Where,

θ_H is winding hot-spot-temperature.

θ_A denotes ambient temperature.

$\Delta\theta_{TO}$ is top-oil rise over ambient temperature.

$\Delta\theta_H$ represents winding hottest-spot rise over top-oil temperature.

$\Delta\theta_{TO,U}$ and $\Delta\theta_{TO,i}$ are ultimate and initial top-oil rise over ambient temperature, respectively.

$\Delta\theta_{H,U}$ and $\Delta\theta_{H,i}$ are ultimate and initial hottest-spot rise over top-oil temperature, respectively.

τ_{TO} and τ_w are oil and winding time constants, respectively.

ξ is hours of operation of a transformer.

$\Delta\theta_{TO,R}$ and $\Delta\theta_{H,R}$ are top-oil rise and hottest-spot rise at rated load, respectively.

K_U is the ratio of ultimate to rated load.

R represents the load loss ratio.

m and n are factors that depend upon the type of cooling of transformers.

2.3.2 Aging Model

The standards [48] - [49] also provide (6) - (8) for calculating the aging and loss-of-life of thermally upgraded paper (reference temperature 110 °C).

$$F_{AA} = \exp\left(\frac{15000}{383} - \frac{15000}{\theta_H + 273}\right) \quad (6)$$

$$F_{EQA} = \sum_{\varepsilon} F_{AA,\varepsilon} \Delta t_{\varepsilon} \Big/ \sum_{\varepsilon} \Delta t_{\varepsilon} \quad (7)$$

$$\%\mathrm{LOL} = F_{EQA} \times (\sum_{\varepsilon} \Delta t_{\varepsilon}) \times 100 \Big/ \text{Normal insulation life} \quad (8)$$

Where,

F_{AA} is the aging acceleration factor.

F_{EQA} represents equivalent aging factor.

ε is the index of time.

Δt is a time interval.

The value of F_{AA} corresponding to a transformer operation at HST of 110°C is unity. It should be mentioned that with continuous operation at this temperature, normal insulation life of the transformer is 20.55 years (180,000 hours) [48].

2.4 Conclusion

This chapter provided the preliminary material related to DR and Transformers. The DR preliminaries included its definition, types, benefits, barriers, and an approach of determining DR capability of a system. Transformer preliminaries covered HST and aging calculation method.

3 Demand Response Benefits for Transformers' Operations

This chapter deals with Task 1 of the dissertation (tasks are defined in Chapter 1). The aim is to present the demand response (DR) benefits of utilization improvement and lifesavings for primary substation (HV/MV) transformers during operational stages. This task is divided into three subtasks. The first subtask deals with the benefit of utilization improvement of transformers during normal operating conditions (without contingency). The second subtask addresses the possibility of lifesaving of transformers using DR during transformer contingencies based on static rating. In the third subtask, an optimization model is proposed by which efficient utilization of transformer and lifesaving benefits for transformers during contingencies can be achieved for transformers irrespective of ambient conditions through dynamic thermal ratings (DTR). The details of subtasks are described in the following sections after the initial section containing introduction and literature review.

3.1 Introduction and Literature Review

Transformers are generally the most expensive and critical element in a power delivery system [2]. Their high utilization efficiency is vital to obtain rational return on investments [1]. Owing to moderate load factor and reserve capacity obligations to provide support during contingencies, utilization efficiency of transformers is ordinary. They are traditionally loaded around 40-60% during normal operations [2]. Furthermore, transformers are overloaded during contingencies due to shifting of disconnected load to healthy transformers in a highly utilized system. These overloads produce heat losses in the transformer that in turn deteriorate the paper insulation at high rate. As health of the paper insulation is the measure of the age of a transformer, therefore, intensity of overloads must be lessened to avoid loss-of-life (LOL) at an accelerated rate. Moreover, investments in transformer capacity are needed to support growing load at peak hour and to replace aging infrastructure. The traditional approach of capacity addition is not economical [4]. Therefore, novel solutions are required to avoid massive upgrade cost of transformers [1]. DR can be used during normal operations and during contingencies to improve asset utilization and to mitigate the LOL.

In literature, various techniques including DR have been proposed for utilization efficiency increase and life extension of transformers. References [50] - [51] propose a scheme to extend the life of secondary distribution transformers by distributed generation. Online condition monitoring, loading equipment up to their dynamic thermal rating (DTR), and continuous removal of aging and degradation products from oil are also used for power transformer life extension and utilization improvement [5]- [7], [52] - [55]. The DTR of transformers have been examined well in [48] - [49]. IEEE standard [48] recommends maximum hottest-spot temperature (HST) of 110°C and 140°C for safe operation of transformers continuously and during contingencies, respectively. However, the use of only DTR cannot offer the substantial potential benefit towards utilization improvement as peak load hours still limit the loading capability. The combination of DR and DTR can deliver the significant improvement in asset utilization efficiency.

The effect of controlled and uncontrolled electric vehicles (EV) charging on secondary distribution (medium-voltage/low-voltage) transformers aging was evaluated by numerous researchers [56]- [60]. In [61] - [62], the problem of additional load of EV charging was solved by DR of flexible household appliances. The DR was used to limit the demand to a certain level; however, DTR was not considered. References [63] - [65] also analyze the impact of EV and DR on primary distribution transformer. A smart distribution transformer management with multi-agent techniques was proposed for DR implementation at a distribution transformer level [66]. Reference [67] proposed transformer terminal unit based integration of DR for transformer management system. Reference [68] investigates the impact of DR on the lifetime of a secondary distribution transformer by optimizing transformer temperature. In that investigation, the thermal dynamics were considered, however, the optimization target of minimizing the sum of HST over a day by DR is not efficient because load rescheduling can only change mean HST if variations in ambient temperature are significant. Furthermore, utilization gain of transformers was not assessed in [68].

Prior to [I], hardly any study has examined the utilization improvement of transformers using DR in combination with DTR. Neither any research investigated the impact of DR in reducing the LOL of power transformers during contingencies until [II] and [III].

3.2 Demand Response Benefit for Normal Operation of Transformers

This section presents the prospective of DR in improving the utilization of transformers during normal conditions. At first, an optimization model is proposed to determine optimal DR activation in order to maintain the HST of a transformer within a certain limit. In the proposed model, a dynamic thermal model is applied to estimate the HST and insulation aging. Then, simulations are performed for case studies of load with and without DR for a primary distribution transformer in a typical Finnish residential area. The analysis results indicate that transformer's utilization can be increased considerably by using DR.

3.2.1 Proposed Model

Fig. 3.1 displays the flow chart of the proposed algorithm for computing the gain in transformer utilization with DR support. The chart comprises of the following eight modules.

- Module 1: The first step is to gather the data related to the system under study. The data contains the information of transformer input parameters for thermal calculations, annual load profile, DR potential of load, ambient temperature, and HST bound.

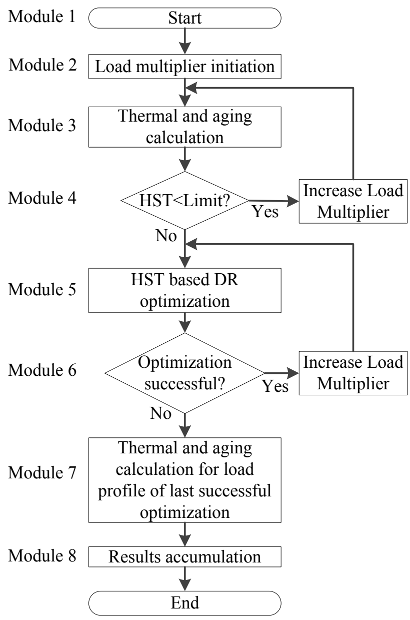

Fig. 3.1. Flow diagram of the proposed algorithm.

- Module 2: The second block initializes the load multiplier that denotes the scaling of the basic load profile. The load multiplier is increased gradually in order to determine the loading limits.
- Module 3: A new load profile is created in this module by multiplying the initial load data with the load multiplier. Then, thermal and aging numerical values are computed for the newly created annual load profile by using (1) - (8).
- Module 4: In this step, the transformer HST, which was calculated in previous module, is compared with the highest permitted value. HST lesser than the predefined limit leads to load multiplier increment until this condition is violated. This module determines the maximum load value for which the transformer HST remains within the bound without activating DR.

- Module 5: The HST of the transformer surpassed the permitted limit for the last loading values in the previous module. Therefore, load reduction by DR activation is needed to keep the transformer operation within the set temperature bound. In this block, the following optimization model is employed to obtain a modified load profile.

The aim is to decrease the HST to a definite value by activating the least amount of load rescheduling under DR during a day. The minimum DR activation is framed in the objective function (9) whereas HST limit is defined by constraint (10).

$$\text{Minimize}\, f = \sum_{t=1}^{24} \sum_{t'} L_{DR}^{t,t'} \tag{9}$$

Where,

t and $t'(>t)$ are the indices of time intervals.

$L_{DR}^{t,t'}$ is a linear variable representing load deferred from one time t to a later time t'.

The optimization function is subject to the following constraints:

$$\theta_{H,t} \le \theta_H \quad \forall t \tag{10}$$

$$\sum_{t'} L_{DR}^{t,t'} \le \sum_{t'} P_{DR}^{t,t'} \quad \forall t' \in t + \{1, 2, 3, ..., T_{DR}^{\max}\} \tag{11}$$

$$P_{tot}^{t} = P_{DR}^{t} + P_{C}^{t} + \sum_{t''} L_{DR}^{t'',t} - \sum_{t'} L_{DR}^{t,t'} \quad \forall t \tag{12}$$

Where,

$\theta_{H,t}$ and θ_H are linear variables for HST at time t and its peak bound, respectively.

t, t', and t'' are indices of time interval.

$T_{DR}^{\max}$ is the maximum time for which a load can be deferred.

$L_{DR}^{t,t'}$ and $P_{DR}^{t,t'}$ are linear variables for load deferred from time t to later time t' and its peak bound, respectively.

$L_{DR}^{t'',t}$ is a linear variable for load deferred to t in prior times t'' (DR load recovery).

P_{DR}^{t} and P_{C}^{t} are available flexible and critical loads at time t, respectively.

P_{tot}^{t} is a modified load profile at time t after DR activation.

In the above formulation, (10) sets the bound on the HST. (11) is the constraint of DR potential; load postponed to a particular later hour should be lesser than the sum of available power that can be delayed to that time or later. The modified load profile after DR activation is given by (12), which is the summation of available responsive load, critical load, and load that was postponed in prior times minus load delayed to later times.

The output of the optimization is the amended load profile (P_{tot}^{t}) and DR activities ($L_{DR}^{t,t'}$) required to decrease the HST to the defined level.

- Module 6: The outcome of the optimization is determined in this step. The success of the optimization designates that the DR activation is capable of decreasing the HST to the desired level. The load multiplier is incremented and steps of Module 5 and 6 are repeated. As the goal of the algorithm is to find the maximum prospective utilization increase of the transformer, therefore, this loop is iterated until the optimization fails to provide an answer. The load multiplier for the final successful optimization provides the maximum utilization improvement of the transformer that can be obtained by DR without violating HST limit.
- Module 7: Here, the thermal and aging values are calculated for the last load profile attained from Module 6.
- Module 8: Lastly, the results of prior modules are gathered.

3.2.2 Case Studies and Results

A typical Finnish residential area primary substation transformer (40 MVA, 110/20 kV) is considered as a test entity [69]. It is supplying power to 1800 households belonging to four primary heating type groups; district heating, direct electric heating, electric storage heating, and ground source heat pump. The load profile of the transformer is formed by using one year hourly measures load data for each type of household in central Finland. The input data for thermal calculations of the primary transformer are listed in Table 3–I. To make the optimization problem solvable by usual solvers, the cooling parameters (m and n) are assumed to be unity [68]. The quadratic optimization problem formulated in Section 3.2.1 is solved via the general algebraic modelling system (GAMS) [70] environment for two case studies designated as Case 1(load is non responsive) and Case 2 (DR enabled load). In both the cases HST peak limit is set to 110°C.

TABLE 3-I

PRIMARY DISTRIBUTION TRANSFORMER PARAMETERS. [71]

Type of cooling.	OFAF
Hottest-spot rise over ambient at rated load.	80 °C
Top-oil rise over ambient at rated load.	56 °C
Load loss at rated load to no-load loss.	6
Winding time constant.	7 min
Oil time constant.	90 min

Table 3–II shows the results for the progressively incrementing loading scenarios that are purposely selected for elaboration of results. Scenario 1 is for the rated load, maximum DTR is presented by scenario 3, and scenario 2 shows loading condition between scenario 1 and of 3 in which DTR is applied on the transformer. Scenarios 4 through 7 represent the progressive loading situations where DR is activated to limit HST below its bound. Scenario 7 indicates

maximum possible loading with accessible DR. In scenario 8, the HST limit is eased to 115°C to assess the extent of winding HST that can be decreased by activating the DR potential of load past scenario 7.

TABLE 3-II

CASE STUDY RESULTS FOR PRIMARY SUBSTATION TRANSFORMER

Scenario	Average Load (p.u.)	Case 1 (without DR)			Case 2 (with DR)			Difference		
		Peak Load (p.u.)	HST max (°C)	LOL (%)	Peak Load (p.u.)	HST max (°C)	LOL (%)	Peak Load (p.u.)	HST max (°C)	LOL (%)
1	0.37	1.00	37	0.00003	1.00	37	0.00003	-	-	-
2	0.52	1.40	80	0.00036	1.40	80	0.00036	-	-	-
3	0.60	1.62	110	0.00494	1.62	110	0.00492	-	-	-
4	0.61	1.65	115	0.00726	1.60	110	0.00692	0.05	5	0.00034
5	0.69	1.85	146	0.10049	1.68	110	0.05063	0.17	36	0.04986
6	0.73	1.95	164	0.37484	1.66	110	0.10478	0.29	54	0.27006
7	0.74	1.98	169	0.55480	1.66	110	0.12780	0.32	59	0.42699
8	0.75	2.00	173	0.71984	1.70	113	0.18072	0.30	60	0.53912

The peak loads of scenario 1 (100%) and scenario 2 (140%) produces a maximum HST of 37°C and 80°C in Case 1, respectively. These small HST values are a result of cold ambient conditions in winter when load peaks occur. In scenario 3 of Case 1, 162% loading generates the HST of 110°C which is set as operational bound. Loading beyond this level requires DR activation in order to maintain the HST within the limit.

In scenario 4 of Case 1, HST rises to 115°C that is brought back to 110°C by optimally delaying the responsive load in Case 2. Likewise, DR activation reduces the maximum HST of scenarios 5, 6, and 7 (146°C, 164°C, and 169°C respectively) to the desired level. Lack of DR potential in decreasing the HST produces no optimization solution for transformer loading beyond 198%.

The transformer can supply any average loading level of 60% (corresponding peak load 162%) without violating HST condition in case DR is not available at load side (Case 1, scenario 3). With the activation of DR (Case 2, scenario 7), the operation up to average loading of 74% is acceptable (corresponding Case 1 peak load 198%). The potential for increase in loading of this transformer by DR is about 36% for peak loading, and corresponding increase in average load is 14%. In each scenario the LOL of transformer is also decreased in Case 2, however, the LOL values are small in both the cases due to overall low average load and cold ambient conditions. The ambient temperature at maximum HST is about -14°C.

The amount of annual load delayed in obtaining the results of Case 2 is given in Table 3–III. The demand delay values are presented based on delay duration (one to five hours) and as fraction of annual demand (W_a). In scenario 4, DR activation on 1818 kWh (0.001% of annual demand) of responsive load decreases the maximum HST by 5°C. Higher reduction in HST requires greater share of load shift under DR. The maximum utilization gain (scenario 7) requires 854 MWh demand shift which reduces the HST by 59°C. This load postponement is equal to 0.33% of the annual demand and major share is constituted by responsive capability of direct space heaters (demand delay for 1 h).

TABLE 3-III
ANNUAL LOAD TRANSFER UNDER DR IN CASE 2 FOR PRIMARY SUBSTATION TRANSFORMER.

Scenario	Total demand shift under DR in a year (kWh)						
(Case 2)	1 h	2 h	3 h	4 h	5 h	Total	% of W_a
4	354	446	398	339	281	1 818	0.001
5	62 755	21 835	22 354	13 658	28 077	148 679	0.062
6	325 826	52 975	49 209	42 558	112 199	582 766	0.229
7	526 472	68 207	67 912	52 507	139 361	854 459	0.330

Fig. 3.2 displays the peak-day primary transformer loading and associated temperatures of both the cases for scenario 5. In Case 1, HST bound is violated for 5 hours (1800 to 2100 and 0000) which are eradicated by DR in Case 2. The total demand modification in the day to restrict the HST to 110°C is 45.64 MWh. The demand postponement for 1, 2, 3, 4 and 5 hours are 28.82, 2.56, 3.77, 3.86, and 6.63 MWh, respectively.

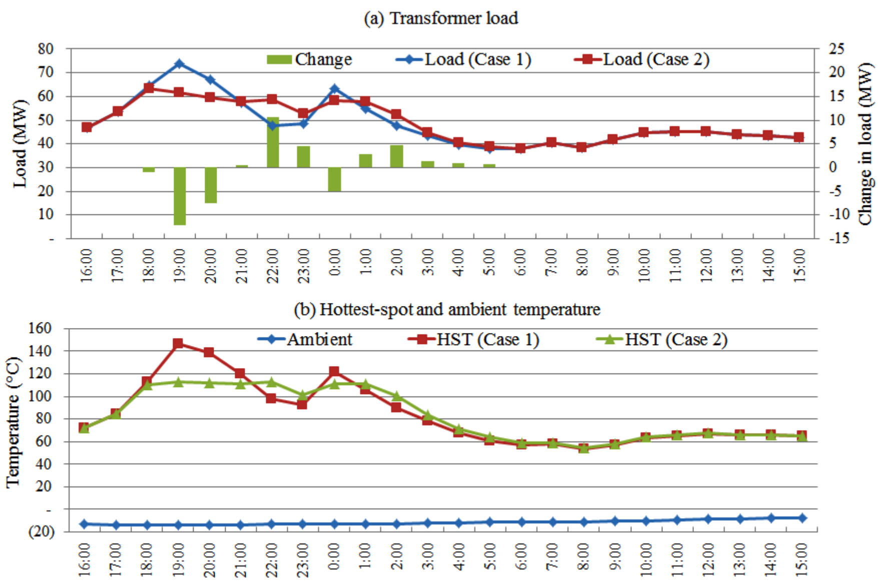

Fig. 3.2. Load and temperature curves of scenario 5's peak day for primary substation transformer.

The following deductions can be made from the case study results:

- The utilization efficiency of transformers can be improved considerably (up to 36% for peak load and 14% for average load). This utilization gain can help in delaying or completely avoiding the transformer investment cost needed to counter load growth or replacement of aged transformers.
- The utilization improvement of transformers by the proposed model does not adversely impact the LOL because the HST is maintained below a defined limit, which is the cause of aging in transformers.

3.3 Demand Response Benefit for Transformers during Contingencies (Based on Static Ratings)

In the previous section transformer utilization gain with DR in normal conditions (without contingencies) was assessed. This section proposes an optimization model for life extension and utilization efficiency improvement of transformers during contingency events by using event driven DR. The optimization model selects the best combination of load relieving options among DR, load curtailment (LC), and transferring load to a neighboring substation (NSS); in order to decrease the loading on an overloaded transformer to a pre-defined level during contingencies. To quantify the DR benefits, simulations are performed for a typical Finnish residential load dominant two-transformer primary substation.

3.3.1 Proposed Optimization Model

Fig. 3.3 shows the flow diagram of the proposed algorithm for calculating the required aging quantities with DR supported loads. The diagram contains the following eight modules.

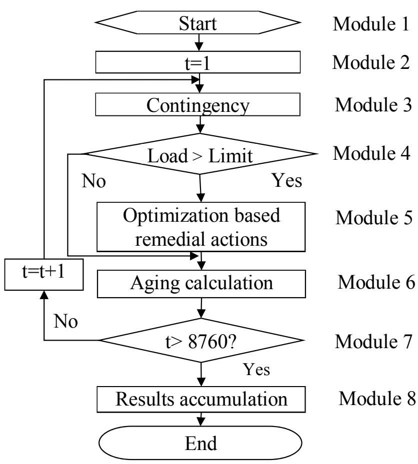

Fig. 3.3. Flow diagram of the proposed algorithm.

- Module 1: The data related to system are gathered in this block. The data may include; transformers size, rating, interconnection, fault rates, repair times, operation procedures, configuration, and load profile.
- Module 2: The nature of power system faults is random and load is hourly varying. Therefore, time of contingency event determines its impact on the system. To cover each hour contingency, the hour counter t is initialized here.
- Module 3: This step introduces a transformer contingency in a multi-transformer substation and disconnected load is shifted to healthy transformer(s) in the same substation.
- Module 4: In this module, the necessity of load alleviation on healthy transformer(s) is judged. The load reduction is needed in case it is more than the acceptable limit.
- Module 5: There are three possible remedial actions for relieving load on the overloaded transformer; transferring load to a NSS, DR activation, and LC. The best combination of remedial actions is decided by the following optimization model.

The goal is to determine the combination of load decreasing actions during transformer repair with the minimum total cost. The mathematical formulation of the optimization problem is as follows:

$$\text{Minimize} f = \sum_{t=1}^{T_r} L_{LC}^{t} \times c_{LC} + b \times c_{SW} + \sum_{t=1}^{T_r} \sum_{t'} (L_{DR}^{t,t'} \times c_{DR}) \quad (13)$$

Where,

t and t' are indices of time interval.

T_r is repair duration of transformers.

L_{LC}^{t} is linear variable for amount of critical load curtailed.

c_{LC} represents the unit load curtailment cost.

b is binary variable that represents the transfer of load to a neighboring substation.

c_{SW} denotes the cost of load shifting to a neighboring substation.

$L_{DR}^{t,t'}$ is linear variable representing load deferred from time t to later time t'.

c_{DR} denotes the unit incentive paid to customers for using their DR flexibility.

The above objective function is subject to the following constraints.

$$P_{tot}^{t} = P_{DR}^{t} + P_{C}^{t} + \sum_{t''} L_{DR}^{t'',t} - L_{LC}^{t} - \sum_{t'} L_{DR}^{t,t'} \quad \forall t \quad (14)$$

$$P_{tot}^{t} \le P_{tran}^{\max} \times P_{tran}^{NP} + b \times P_{NSS} \quad \forall t \quad (15)$$

$$0 \le L_{LC}^{t} \le P_{DR}^{t} + P_{C}^{t} - \sum_{t'} L_{DR}^{t,t'} + \sum_{t''} L_{DR}^{t'',t} \quad \forall t \quad (16)$$

$$\sum_{t'} L_{DR}^{t,t'} \le \sum_{t'} P_{DR}^{t,t'} \quad \forall t' \in t + \{1,2,3,\ldots,T_{DR}^{\max}\} \quad (17)$$

Where,

t , t' , and t'' are indices of time interval.

P_{tot}^{t} is modified load profile at time t after DR activation.

P_{tran}^{NP} and $P_{tran}^{\max}$ are transformer nameplate ratings and maximum permitted load in per unit, respectively.

P_{NSS} represents the neighboring substation load receiving capacity.

P_{DR}^{t} and P_{C}^{t} are available flexible and critical loads at time t , respectively.

$L_{DR}^{t,t'}$ and $P_{DR}^{t,t'}$ are linear variable for load deferred from time t to later time t' and its peak bound, respectively.

$L_{DR}^{t'',t}$ represents load deferred to t in prior times t'' (DR load recovery) variable.

$T_{DR}^{\max}$ denotes the maximum time for which a load can be deferred.

Equation (14) calculates the modified load profile after load curtailment and DR activation. Constraint (15) ensures that the modified load profile is always lesser than the defined limit (sum of transformer emergency ratings and neighboring substation capacity). The upper load curtailment limit set by (16) depends upon available critical and responsive load, load delayed to later times, and DR load recovery. (17) is the constraint of DR potential; load postponed to particular later hour should be lesser than sum of available power that can be delayed to that time or later.

The output of the optimization is the modified load profile, necessary actions required to restrict load on transformers, and conforming cost of modifications.

- Module 6: In this module, optimized load profile along with weather and transformer input data are used to determine the aging and LOL quantities.
- Module 7: To cover a full year, steps of Modules 3 - 8 are repeated 8760 times.
- Module 8: Finally, each time step contingency results are gathered for analysis and reporting.

3.3.2 Case Studies and Results

A typical Finnish residential two-transformer primary distribution substation (110 kV/20 kV), as Fig. 3.4 schematized, is used as a test system. The primary substation contains two identical transformers (40 MVA each) which acts as back-up to each other during contingencies. The present peak of typically hourly varying load at each transformer is 24 MVA.

The input data for thermal calculations and values of optimization parameters are listed in Table 3–IV and Table 3–V, respectively. The mixed integer linear optimization problem framed in Section 3.3.1 is solved via the general algebraic modelling system (GAMS) environment.

Typical diurnal and seasonal variations of the Finnish ambient temperature are also considered in the analysis.

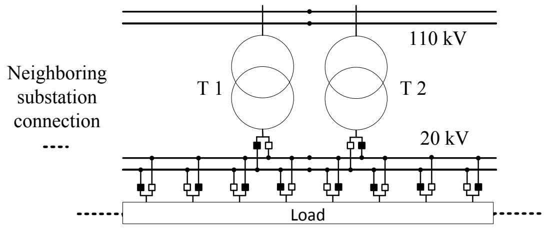

Fig. 3.4. Single-line diagram of the test system (a typical Finnish substation).

TABLE 3-IV

PRIMARY DISTRIBUTION TRANSFORMER PARAMETERS.

Type of cooling (m/n).	OFAF(0.8/0.9)
Hottest-spot rise over ambient at rated load.	80 °C
Top-oil rise over ambient at rated load.	56 °C
Load loss at rated load to no-load loss.	6
Winding time constant.	7 min
Oil time constant.	90 min

TABLE 3-V

VALUES OF OPTIMIZATION PARAMETERS FOR TEST NETWORK

Cost of load curtailment (c_{LC}).	10 €/kWh
Cost of demand response activation (c_{DR}).	0.20 €/kWh
Cost of load switching to neighboring substations: 6 man-hours (c_{SW}).	90 €
Maximum allowed loading of transformer ($P_{Tran}^{\max}$).	1.2 p.u.

Simulations are conducted for the following case studies assuming scenarios of progressively growing load and considering single transformer contingency in the substation. The loading scenarios are intentionally selected for elaboration of results.

- Case 1: In this case, the entire load is considered to be critical. The only way of relieving an overload condition (more than 120%) is by shifting load to an adjacent transformer otherwise transformers are allowed to violate the loading limit. This case provides LOL benchmark for the established methodology.
- Case 2: In addition to load transfer to neighboring substation, load curtailment is also considered as a choice in bringing transformers' operation within the set limit in this case.

This case provides the base cost of load reduction for comparison between cases of load with and without DR.

- Case 3: Event driven working DR is also assumed in this case. Here, DR potential activated by the proposed optimization model assists the network operators to relieve transformer overloads by delaying responsive loads to later times.

The results of above case studies are illustrated below for summer and winter contingencies in two situations; NSS support absent and available.

Neighboring Substation Support: Absent (Summer Contingency)

Table 3–VI demonstrates the LOL comparison for a near-peak transformer contingency in summer while connection to adjacent substations is not available. In scenario 1, overload is not observed even during contingency (peak load 120%). For other scenarios, transformer contingency produces overload on healthy transformer (Case 1) which is removed by LC (Case 2) and optimal remedial actions (Case 3).

TABLE 3-VI
LOSS-OF-LIFE COMPARISON FOR CASE STUDIES CONSIDERING CONTINGENCY NEAR-PEAK LOAD

Scenario	Normal peak	Loss-of-life (%)			Lifesaving (Aging Hours)		
#	(%)	Case 1	Case 2	Case 3	Case 2	Case 3	[Case 2-Case 3]
1	60	0.0038	0.0038	0.0038	-	-	-
2	65	0.0125	0.0087	0.0098	7	5	2
3	70	0.0426	0.0181	0.0220	44	37	7
4	74	0.1139	0.0291	0.0368	153	139	14
5	75	0.1456	0.0324	0.0419	204	187	17
6	80	0.4932	0.0545	0.0713	790	760	30
7	90	5.3341	0.1380	0.1617	9 353	9310	43

Table 3–VII lists the load reduction actions needed to obtain the results of Table 3–VI. Fig. 3.5 and 3.6 displays the load, temperature, and aging rate curves for scenario 3 and 5, respectively. In Case 1 of scenario 3, load on the transformer is higher than the limit for twelve hours and the transformer observe the peak load of 56 MW (Fig. 3.5a). Transformer maximum HST, maximum aging acceleration rate, and corresponding ambient temperature are 137 °C, 13, and 16 °C, respectively (Fig. 3.5b). In Case 2, LC of 49.88 MWh (cost 498.81 k€) provides the lifesaving value of 44 aging hours. Case 3 offers lifesaving gain of 37 aging hours during transformer contingency operation by delaying 77 MWh of demand (cost 15.40 k€). The maximum HST and corresponding aging acceleration rates in Case 3 are 120 °C and 2.7. In DR case, the valley filling by payback load generates lower aging benefit as compared to that of Case 2 in which peaks are only clipped by LC. Moreover, mitigation of rebound load peaks requires extra DR actions, therefore, the quantity of total demand deferred in Case 3 (77 MWh) is higher than the LC in Case 2 (49.88 MWh).

TABLE 3-VII
LOAD REDUCTION ACTIONS AND ASSOCIATED COST FOR NEAR-PEAK TRANSFORMER CONTINGENCY IN CASE 2 AND CASE 3

Scenario	Load curtailed (MWh)		Demand deferred in Case 3 (MWh)						Cost of load reduction (k€)		
#	Case 2	Case 3	1 h	2 h	3 h	4h	5 h	Total	Case 2	Case 3	Case 2 – Case 3
2	16.23	-	6.6	3.9	3.3	2	1.7	17.5	162.30	3.50	158.80
3	49.88	-	42	8.8	10	7.1	9.1	77	498.81	15.40	483.41
4	102.37	-	159.2	13.7	14.3	12.4	31.6	231.2	1023.74	46.24	977.50
5	120.58	4.1	170.5	15.7	17	15.3	35.6	254.1	1205.80	91.82	1113.98
6	231.09	37.3	283	21.1	20.9	27.7	94.2	446.9	2310.91	462.38	1848.53
7	621.66	366.5	299.5	32.3	35.8	40.8	109.3	517.6	6216.60	3768.52	2448.08

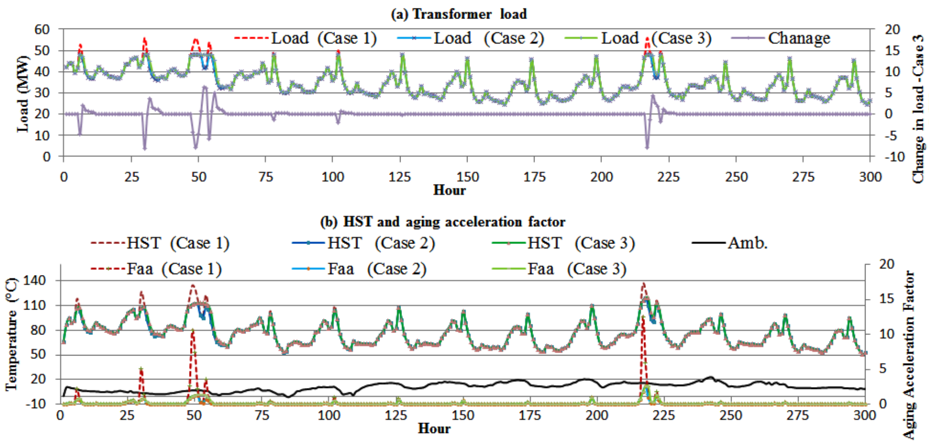

Fig. 3.5. Load, temperature, and aging acceleration factor curves for near-peak contingency in scenario #3.

Fig. 3.6 illustrates the loading and related HST in all the cases for scenario #5. The peak load reduction from 60 MW to 48 MW is attained by 120.58 MWh of LC in Case 2 (cost 1205.8 k€). The equal amount of peak clipping in Case 3 requires 4.1 MWh of LC and 254.1 MWh of demand delay (cost 91.82 k€). As depicted in Fig. 3.6b, DR actions are required at hour 52 and 53 even in presence of small valley because load postponed in prior times creates a new peak here. At the hour 48, part of the load is curtailed even in presence of sufficient responsive load in order to reduce the demand to the set level; because demand deferral at this hour will form rebound peaks at later hours thus requiring demand modifications on at least ten upcoming hours. In such a condition, higher cost of overall load deferment compared to LC or responsive load limit at any hour confines DR operation. The results (Table 3–VII) show that Case 2 needs fewer alterations in load as compared to Case 3, however, the cost of load alleviation is lower in Case 3 due to less expense of DR actions.

The maximum utilization of transformers is 74% (Case 3-scenario 4) by using only DR while satisfying the peak load bound. This indicates that DR support during contingency can improve the normal utilization efficiency of transformers by 14%.

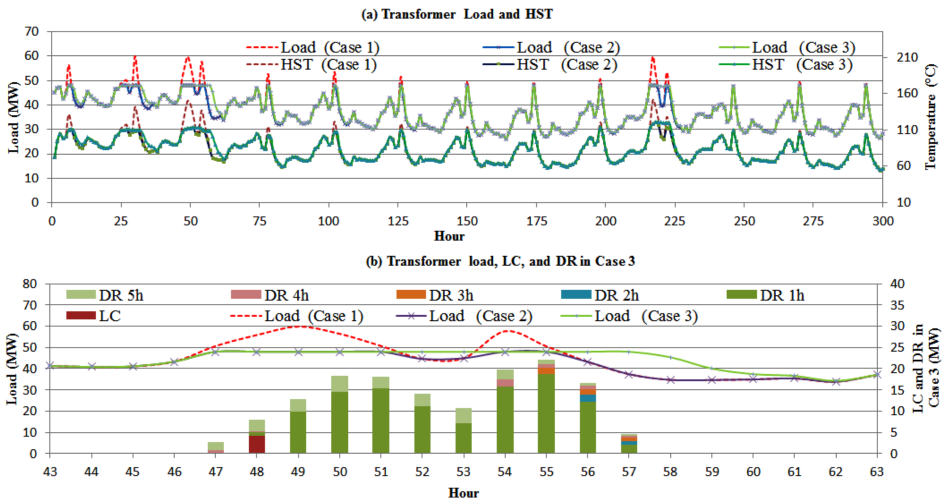

Fig. 3.6. Load, temperature, and load reduction actions for near-peak contingency in scenario #5.

Neighboring Substation Support: Available (Summer Contingency)

Here, it is assumed that support from an identical neighboring substation is available during contingencies. In such a system, single transformer contingency can be fully supported for 90% utilized transformers (given maximum long-term emergency loading of transformers is 120%). At peak, the total load of four transformers located at two substations is (90×4=) 360% and the total capacity of these substations during a transformer contingency would also be (120×3=) 360%. Table 3–VIII and 3–IX show the results and associated costs for a near-peak transformer contingency in summer, respectively. In contrast to without neighboring substation situation, LOL values in Case 1 for the selected scenarios are high as transformers are highly loaded before and during repair time. Therefore, decrease in load during the contingency results into relatively superior aging benefits.

The lifesaving benefits are obtained in all the scenarios of Case 2 and 3, however, the costs of load decrease are low only for scenarios a-e in Case 3. In these scenarios, sufficient DR capability minimizes or eliminates the activation of costly load curtailment. In scenarios a and b of Case 2 and 3, the activation of LC/DR during load transfer to the NSS (requiring 3h for manual transfer) generates lifesaving benefit though rest of the transformers are able to take the entire disconnected load.

TABLE 3-VIII

LOSS-OF-LIFE COMPARISON FOR CASE STUDIES CONSIDERING CONTINGENCY NEAR-PEAK LOAD (NEIGHBORING SUBSTATION CONNECTED)

Scenario	Normal peak (%)	Loss-of-life (%)			Lifesaving (Aging Hours)		
		Case 1	Case 2	Case 3	Case 2	Case 3	[Case 2-Case 3]
a	80	0.0554	0.0545	0.0550	1.6	0.8	0.9
b	90	0.1503	0.1380	0.1380	22.1	22.1	-
c	95	0.2450	0.1807	0.1809	115.7	115.4	0.3
d	98	0.4042	0.2064	0.2076	355.9	353.9	2.1
e	99	0.5156	0.2151	0.2169	540.8	537.6	3.2
f	100	0.6855	0.2237	0.2260	831.1	827.0	4.1
g	105	4.5267	0.2622	0.2713	7676.1	7659.7	16.3

TABLE 3-IX

LOAD REDUCTION ACTIONS AND ASSOCIATED COST FOR NEAR-PEAK TRANSFORMER CONTINGENCY IN CASE 2 AND 3 (NEIGHBORING SUBSTATION CONNECTED)

Scenario	Load curtailed (MWh)		Demand deferred in Case 3 (MWh)						Load transferred (MWh)		Cost of load reduction (k€)		
#	Case2	Case3	1 h	2 h	3 h	4h	5 h	Total	Case 2	Case 3	Case 2	Case 3	Case 2 - Case 3
a	4.8	-	1	1.2	1	0.8	0.8	4.8	226.2	228.5	48.08	1.05	47.03
b	23.4	-	24.3	2.4	3.2	2	1.5	33.5	598.2	621.6	234.07	6.79	227.28
c	71.5	-	63.1	10.6	10.8	10.9	9.5	104.9	889.5	959.1	715.05	21.07	693.98
d	131.3	-	166.3	13.1	17.3	19.4	43.7	259.8	1062.9	1181.5	1312.73	52.05	1260.68
e	163.4	0.2	266.0	16.9	20.2	18.8	59.7	381.7	1113.4	1258.8	1634.23	78.43	1555.80
f	202.7	7.1	333.6	20	24.7	24.2	73.4	475.9	1159.5	1332.3	2027.81	166.27	1861.54
g	475.1	193.2	323.8	35.6	40.5	49.7	149.9	599.4	1354.8	1575.5	4751.15	2051.97	2699.18

Fig. 3.7 presents the load, temperature, and aging rate curves for scenario c. In Case 1, load on the transformer is higher than the limit for ten hours at various instances and the transformer observe the peak load of 59.95 MW (Fig. 3.7a). This peak occurs at hour 3 where load transfer to the neighboring substation is being initiated. The corresponding ambient temperature, HST, and aging acceleration rate are 10 °C, 151 °C and 44, respectively (Fig. 3.7b). In Case 2, LC of 71.55 MWh (cost 715.05 k€) delivers the lifesaving benefit of 115.7 aging hours. Case 3 provides gain of 115.4 aging hours during transformer contingency operation by postponing 104.9 MWh of demand (cost 21.07 k€). The maximum HST and consistent aging acceleration rates in Case 3 are 129 °C and 6, respectively.

Scenario d (98% normal loading) corresponds to maximum transformers' capacity utilization where load is decreased to the set limit (120%) without curtailing any part of critical load in Case 3. It designates that the utilization of all the transformers can be increased by 8% in normal conditions by deploying DR as a solution of decreasing load during contingencies. Thus, the total utilization increase of four transformers would be (8×4=) 32%.

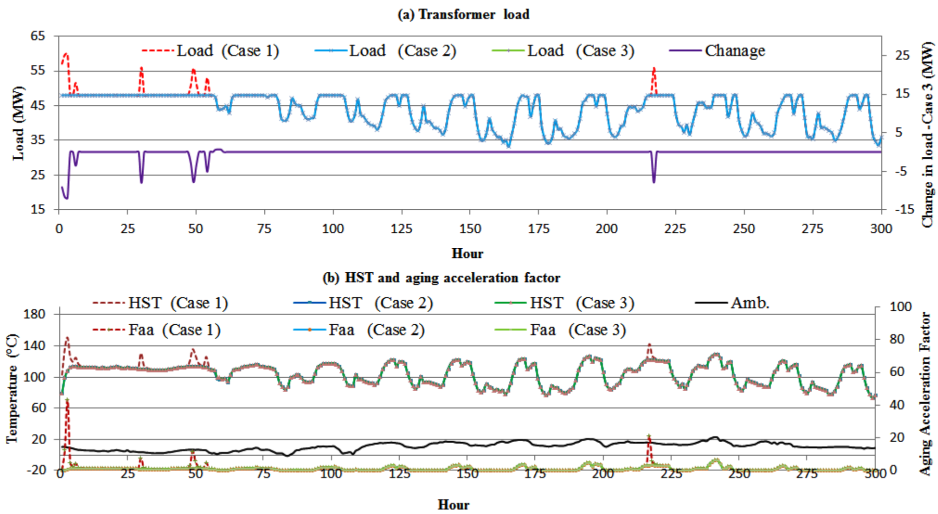

Fig. 3.7. Load, temperature and aging acceleration factor curves for near-peak contingency in scenario c (neighboring substation connected).

Winter Contingencies

Table 3–X and 3–XI list the results of case studies for near-peak load contingency in winter when the neighboring substation support is absent and available, respectively. The ambient temperature varies between -28 °C and 1 °C during the repair of the transformers. The lifesaving benefits are also attained here and its trend with growth in load is the same as of summer contingencies. However, the scale of the benefit is less in winter. These lower gains are due to very low ambient temperatures that creates trivial aging of transformers even in Case 1. Thus, the decrease of load in Case 2 and 3 by LC/DR yields a slighter effect on aging of transformers.

In Case 3-scenario 4, peak clipping reduces the HST from 126 °C (Case 1) to 92 °C that results into lifesaving benefit of 16.3 aging hours. Similarly, Case 3-scenario d produces 34.8 aging hours benefit and corresponding change in HST is from 132 °C (Case 1) to 93 °C. The ambient temperature at these HST peaks is -8 °C.

TABLE 3-X

LOSS-OF-LIFE COMPARISON FOR CASE STUDIES CONSIDERING CONTINGENCY NEAR-PEAK LOAD IN WINTER.

Scenario	Normal peak	Loss-of-life (%)			Lifesaving (Aging Hours)		
#	(%)	Case 1	Case 2	Case 3	Case 2	Case 3	[Case 2-Case 3]
1	60	0.0002	0.0002	0.0002	-	-	-
2	65	0.0010	0.0006	0.0007	0.6	0.5	0.1
3	70	0.0040	0.0014	0.0018	4.6	4.0	0.6
4	74	0.0122	0.0024	0.0031	17.7	16.3	1.4
5	75	0.0161	0.0027	0.0036	24.2	22.6	1.7
6	80	0.0643	0.0048	0.0068	107.1	103.5	3.6
7	90	0.9344	0.0137	0.0180	1657.2	1649.5	7.7

TABLE 3-XI
LOSS-OF-LIFE COMPARISON FOR CASE STUDIES CONSIDERING CONTINGENCY NEAR-PEAK LOAD IN WINTER (NEIGHBORING SUBSTATION CONNECTED)

Scenario	Normal peak (%)	Loss-of-life (%)			Lifesaving (Aging Hours)		
		Case 1	Case 2	Case 3	Case 2	Case 3	[Case 2-Case 3]
a	80	0.0049	0.0048	0.0048	0.2	0.1	0.1
b	90	0.0142	0.0137	0.0137	0.9	0.9	-
c	95	0.0232	0.0184	0.0185	8.6	8.5	0.1
d	98	0.0411	0.0215	0.0218	35.3	34.8	0.5
e	99	0.0552	0.0225	0.0229	58.8	58.1	0.7
f	100	0.0781	0.0236	0.0240	98.2	97.3	0.8
g	105	0.7472	0.0285	0.0302	1293.6	1290.6	3.1

The following inferences can be drawn from the case study results:

- The LOL of healthy transformers can be decreased in a substation using DR following a contingency.
- The capacity utilization efficiency of transformers can be significantly enhanced by deploying DR as a load amendment tool to limit peak load on healthy transformers during emergencies. This utilization gain can help in postponing or entirely eliminating the transformer investment cost required to counter load growth.
- The lifesaving benefits of peak clipping using DR are ample in a highly utilized system.
- The transformers' aging reduction by peak trimming depends on the ambient conditions. These reductions are superior in warm ambient conditions.
- Load decrease by DR is not always a feasible option as rebound load may create new spikes resulting into series of DR actions to eliminate the new spikes. Thus, for the best result, selection of optimal combination among available choices is crucial.

3.4 Demand Response Benefit for Transformers during Contingencies (Based on Dynamic Ratings)

The preceding section described the method of transformer life extension and capacity utilization improvement by limiting the peak load to the predefined level during contingencies. This section proposes a DR and DTR based optimization model for efficient capacity utilization and life management of transformers during contingencies while maintaining the winding HST within a definite limit. The model elects for the optimal combination of corrective actions among LC, DR, and shifting load to an adjacent substation. Simulations performed on a typical Finnish two-transformer primary distribution substation indicate the worth of the proposed model.

3.4.1 Proposed Optimization Model

The flow diagram of the proposed algorithm for making HST based optimal decisions to alleviate the overload state of transformers during contingencies is exhibited in Fig. 3.8. The graph consists of the following nine modules.

- Module 1: At first, system related data is obtained. The data is composed of information such as transformers type, rating, HST limit, interconnection, fault rates, repair times, configuration, and load.
- Module 2: This block initializes the hour counter t which is used to investigate the likely contingencies at each hour of the year.
- Module 3: A transformer contingency event in a multi-transformer substation is introduced at this stage.
- Module 4: At this step, a new demand profile is formed by shifting load of the faulty transformer to the healthy transformer (s). Then, thermal and aging values are estimated for the new profile using (1) - (8).
- Module 5: Here, the decision of carrying load modification actions is taken by comparing the HST of the healthy transformer and its maximum permissible limit.

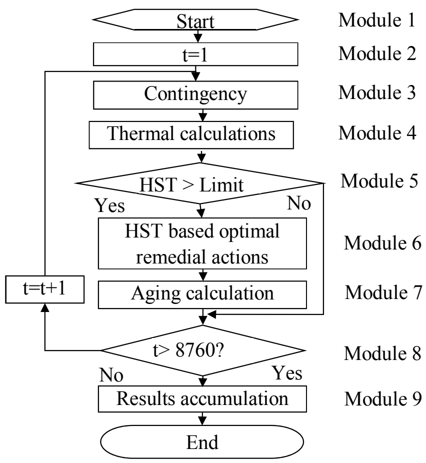

Fig. 3.8. Flow diagram of the proposed algorithm.

- Module 6: The healthy transformer load can be reduced to bound HST using three ways; DR activation, LC, and relocating load to an adjacent substation. Following optimization model determines a suitable combination of load reduction options.

The objective is to minimize the total cost of load reduction during repair duration as formulated below.

$$\text{Min} f = \sum_{t=1}^{T_r} L_{LC}^{t} \times c_{LC} + b \times c_{SW} + \sum_{t=1}^{T_r} \sum_{t'} L_{DR}^{t,t'} \times c_{DR} \tag{18}$$

Where,

t and t' are indices of time interval.

T_r is repair duration of transformers.

L_{LC}^{t} is a linear variable for amount of critical load curtailed at time t.

c_{LC} represents the unit load curtailment cost.

b is a binary variable that represents the transfer of load to a neighboring substation.

c_{SW} denotes the cost of load shifting to a neighboring substation.

$L_{DR}^{t,t'}$ is linear variable representing load deferred from one time t to a later time t'.

c_{DR} denotes the unit incentive paid to the customer for using their DR flexibility.

The optimization objective is subject to the following constraints.

$$P_{tot}^{t} = P_{DR}^{t} + P_{C}^{t} + \sum_{t''} L_{DR}^{t'',t} - \sum_{t'} L_{DR}^{t,t'} - L_{LC}^{t} - b \times P_{NSS} \quad \forall t \tag{19}$$

$$\theta_{H,t} \le \theta_{H} \quad \forall t \tag{20}$$

$$0 \le L_{LC}^{t} \le P_{DR}^{t} + P_{C}^{t} - \sum_{t'} L_{DR}^{t,t'} + \sum_{t''} L_{DR}^{t'',t} \quad \forall t \tag{21}$$

$$\sum_{t'} L_{DR}^{t,t'} \le \sum_{t'} P_{DR}^{t,t'} \quad \forall t' \in \{1,2,3,...,T_{DR}^{\max}\} \tag{22}$$

Where,

t, t', and t'' are indices of time interval.

P_{tot}^{t} is modified load profile at time t after DR activation.

P_{DR}^{t} and P_{C}^{t} are available flexible and critical loads at time t, respectively.

P_{NSS} represents the neighboring substation load receiving capacity.

$L_{DR}^{t,t'}$ and $P_{DR}^{t,t'}$ are linear variable for load deferred from time t to later time t' and its peak bound, respectively.

$L_{DR}^{t'',t}$ represents load deferred to t in prior times t'' (DR load recovery) linear variable.

$\theta_{H,t}$ and θ_{H} are linear variable for HST at time t and its peak bound, respectively.

$T_{DR}^{\max}$ denotes the maximum time for which a load can be deferred.

The modified load profile is determined by (19) which depend upon available flexible load, critical load, load deferred in prior times, load postponed to later times, load curtailed, and load shifted to the neighboring substation. Constraint (20) bounds the HST of the healthy transformer. The upper limit of LC is defined by (21). (22) ensures that the demand postponed at any time is not more than the overall DR capacity of load at that time.

The altered demand profile, the required remedial actions taken, and the consistent cost of load alteration are the yield of the optimization.

- Module 7: In this step, HST and aging calculation are performed using modified load profile.
- Module 8: Steps of Modules 3 - 7 are revisited 8760 times to cover a whole year.
- Module 9: In the end, all the results are gathered for investigation and reporting.

3.4.2 Case Studies and Results

The test system of Section 3.3.2 consisting of a typical Finnish two-transformer primary substation is also used here. Simulations are performed for gradually increasing load for the following case studies assuming a transformer contingency. The maximum allowable HST of the transformer is set as 130 °C.

- Case 1: In the base case, load is considered firm. To bound the HST, the only option accessible is to shift load to the NSS otherwise transformers are allowed to surpass the HST limit set by the network operators. This case sets the benchmark for LOL comparison.
- Case 2: LC is also included as a choice to maintain HST of transformers. This case gives the cost of limiting HST without DR.
- Case 3: Functional DR is also considered in this case. Transformer operation within HST limit is guaranteed by choosing an optimal combination of load transfer, LC, and DR.

The results of above case studies are demonstrated for winter and summer contingencies in two situations; neighboring substation support absent and available. With reference to Case 3, scenarios are deliberately nominated for explanation of the results. These scenarios are for rated load established on static rating (S#1/S#a), acceptable load based on HST bound without triggering DR (S#2), arbitrary load level with DR needed to fulfill HST limit (S#3/S#b), maximum load increase that can be managed by available DR (S#4/S#c), and LC also required along with other choices to satisfy the HST condition (S#5/S#d and S#6/S#e).

Neighboring Substation Support: Absent

Table 3–XII and 3–XIII provide the results of a near-peak transformer contingency in winter and summer respectively, when support from the neighboring substation is not available. The ranges of ambient temperature during contingencies in winter and summer are from -28 °C to 1 °C and from -3 °C and 18 °C, respectively. For loading beyond S#2, transformer HST is above 130 °C in Case 1, LC in Case 2 and optimal combination of corrective actions in Case 3 are able to decrease the HST to the defined limit by reducing the observed peak load. The cost of limiting HST is higher in Case 2 due to LC while use of optimal combinations in Case 3 makes it less expensive.

TABLE 3-XII

CASE STUDIES' RESULTS FOR NEAR-PEAK LOAD TRANSFORMER CONTINGENCY IN WINTER (NEIGHBORING SUBSTATION SUPPORT: ABSENT)

S#	Normal Peak (p.u.)	Case 1 HST max (°C)	Case 1 LOL (h)	Case 2 HST max (°C)	Case 2 LOL (h)	Case 2 Cost (k€)	Case 3 HST max (°C)	Case 3 LOL (h)	Case 3 Cost (k€)	Lifesavings Case 2 (h)	Lifesavings Case 3 (h)	Lifesavings Case 2-3 (h)	Cost Case 2-3 (k€)
1	0.6	93	0.69	93	0.69	-	93	0.69	-	-	-	-	-
2	0.7	129	21	129	21	-	129	21	-	-	-	-	-
3	0.75	149	118	130	62	93.22	130	68	2.37	56	50	6	91
4	0.85	193	3173	130	219	886.2	130	264	46.1	2954	2909	46	840
5	0.86	197	4360	130	242	1043	130	290	87.85	4118	4070	49	955
6	0.9	217	15185	130	354	1829	130	438	342	14831	14747	84	1487

TABLE 3-XIII

CASE STUDIES' RESULTS FOR TRANSFORMER CONTINGENCY IN SUMMER (NEIGHBORING SUBSTATION SUPPORT: ABSENT)

S#	Normal peak (%)	Loss-of-life (h) Case 1	Loss-of-life (h) Case 2	Loss-of-life (h) Case 3	Lifesavings (h) Case 2	Lifesavings (h) Case 3	Lifesavings (h) Case 2-3
1	0.6	7	7	7	-	-	-
2	0.65	32	32	32	-	-	-
3	0.7	149	87	93	62	56	7
4	0.78	1707	226	274	1481	1433	48
5	0.79	2306	252	308	2054	1998	56
6	0.85	13575	443	581	13132	12994	139

Fig. 3.9 demonstrates the loading and consistent HST for all the cases of S#5 (86% normal peak) in winter. The HST above 130 °C occurs for 28 hours at different instances in Case 1. The HST bound is fulfilled in Case 2 by LC of 104.3 MWh at cost of 1043 k€. For the same HST condition, LC of 3.69 MWh and demand rescheduling of 254.65 MWh at total cost of 87.85 k€ are required in Case 3. At hour 48, a small volume of load is curtailed even in the existence of adequate DR because demand postponement at this hour results into higher cost of load modification for forthcoming hours. Similarly, DR is triggered during hour 52 and 53 in order to eliminate formation of a new peak. LOL during contingency operation is decreased from 4360 aging hour (Case 1) to 290 aging hours in Case 3.

In winter, the maximum use of transformers without using LC while satisfying the HST limit is 85% (in Case 3-S#4). This points out that the extra 25% capacity of each transformer can be used in normal circumstances by using only DR in contingencies. At the same time, the lifesaving advantage for this scenario has also significantly large value (2909 aging hours). In summer, significant lifesaving of 1433 aging hours is also acquired in Case 3 for S#4 (agreeing the condition that only DR along with DTR is activated). Here, corresponding utilization improvement per transformer is 18% which is lesser than the winter contingencies due to higher ambient temperatures in summer. The higher ambient temperature produces HST close to the defined limit at lower level of loads.

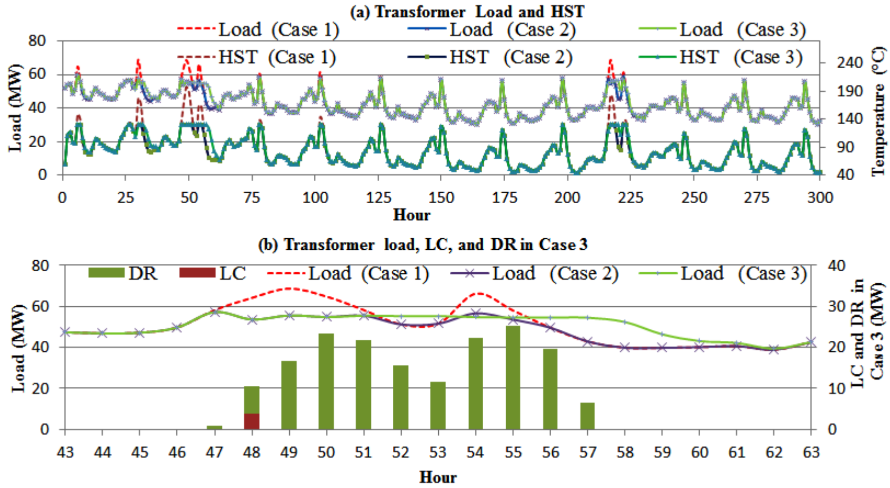

Fig. 3.9. Load, temperature, and HST limiting actions for contingency in S#5 (Winter).

Neighboring Substation Support: Available

Here, it is assumed that the load can be transferred to a NSS of equal capacity during contingencies if free capacity is available there. The results of near-peak transformer contingency in winter and summer are listed in Table 3–XIV and 3–XV, respectively. The results show that lifesaving gains are achieved by keeping the HST to 130 °C in the scenarios (S#b - S#e) of Case 2 and Case 3. The cost of corrective actions and aging gains are directly related to the level of loading. These gains are superior to the benefits of cases without NSS support.

TABLE 3-XIV
CASE STUDIES' RESULTS FOR NEAR-PEAK LOAD TRANSFORMER CONTINGENCY IN WINTER (NEIGHBORING SUBSTATION SUPPORT: AVAILABLE)

S#	Normal Peak (p.u.)	Case 1 HST max (°C)	Case 1 LOL (h)	Case 2 HST max (°C)	Case 2 LOL (h)	Case 2 Cost (k€)	Case 3 HST max (°C)	Case 3 LOL (h)	Case 3 Cost (k€)	Lifesavings Case 2 (h)	Lifesavings Case 3 (h)	Lifesavings Case 2-3 (h)	Cost Case 2-3 (k€)
a	0.9	130	478	130	478	0.09	130	478	0.09	-	-	-	-
b	0.95	147	830	130	764	61.59	130	790	1.32	66	40	26	60.3
c	1.04	205	11692	130	1178	1952	130	1284	94.3	10514	10408	106	1857.8
d	1.05	215	21240	130	1212	2480	130	1328	235.7	20028	19912	116	2244.4
e	1.07	235	70192	130	1300	3780	130	1408	842.3	68892	68784	108	2937.8

TABLE 3-XV
CASE STUDIES' RESULTS FOR TRANSFORMER CONTINGENCY IN SUMMER (NEIGHBORING SUBSTATION SUPPORT: AVAILABLE)

S#	Normal peak (p.u.)	Loss-of-life (h)			Lifesaving (h)		
		Case 1	Case 2	Case 3	Case 2	Case 3	Case 2-3
a	0.9	1100	910	936	190	164	26
b	0.95	1646	1146	1206	500	440	60
c	1.01	11366	1364	1444	10002	9922	80
d	1.02	18050	1412	1486	16638	16564	74
e	1.04	49414	1484	1588	47930	47826	104

In winter, only DR is adequate to uphold the HST limit for normal peak load up to 104% (Case 3-S#c). The amount of demand postponed and transferred to the adjacent substation for this scenario are 1168 MWh and 471 MWh, respectively at total cost of 94 k€. Beyond this load level, price of LC makes the utilization improvement costly. The lifesaving benefit for this scenario is also noticeably large (10408 aging hours). Owing to the results, 14% of utilization enhancement per transformer at both substations can be achieved.

Like the results of the situation without adjacent substation support, summer near-peak load contingency results (Table 3–XIII) indicate overall lesser utilization increase per transformer compared to winter contingencies without using LC (11% for Case 3-S#c). The warmer ambient condition is the cause of this comparatively lower benefit. However, the lifesaving gain is sizable here as well (9922 aging hours). It is worth mentioning that for S#a in Case 2 and Case 3, lifesaving benefits are obtained due to demand reduction during the immediate hours following the contingency when load transferring actions are being originated.

The above analysis provides the following inferences:

- DR can be utilized for transformers' lifesaving and utilization improvements during contingencies.
- The proposed HST limit based model is applicable for lifesaving of transformers for all type of ambient conditions because DR decisions are based on HST which integrally considers outdoor temperature.
- Utilization gain above static limit is greater for transformers installed in cooler climatic areas.
- The selection of optimal combination of load modifying techniques is crucial to evade excess costs that may appear in order to alleviate peak rebounds of DR.

3.5 Conclusion

Transformers' capacity utilization improvement and lifesavings are vital for cost-effective power distribution system. This chapter presented a comprehensives study on the use of DR for utilization improvement and lifesaving of transformers in normal conditions and during contingencies. Firstly, appropriate optimization models were proposed to investigate the intended benefits. Then, simulations were performed based on the models considering typical Finnish systems. The results of the study indicated that significant benefits in terms of lifesaving and capacity utilization improvement can be obtained by employing DR and optimal decisions of DR activation are vital to obtain these benefits with least cost. The utilities can use the proposed model to measure the worth of DR before making the real implementations.

4 Demand Response and Transformers' Capacity Planning

Chapter 3 focused on the management of transformer capacity and life during operational stages. This chapter addresses the planning of transformer capacities in substations over long-run (Task 2). After the introduction and literature review section, an optimization tool is devised for capacity planning of transformers. Next, the optimization model of the tool is reformed to add the features of DR and network automation. Both the developed tools are used for substation capacity planning in various situations encountered by utilities with in their respective sections.

4.1 Introduction and Literature Review

The effective planning of substation transformers' capacity is crucial for an economical power system [2]. The nature of the capacity planning of transformers is long-term due to their immense investment, operational, and reliability cost, long expected life, and requirements to meet demand growth [72] - [74]. An ideal planning tool balances the contradicting objects of higher utilization and lower cost of losses, unsupplied load, and aging rate [75]. The outputs of such a planning tool are selection of transformer sizes from available contenders, their level of loading, maintenance plan, and years of replacement or capacity addition [72], [74] - [77].

Several researchers have addressed the issue of transformer capacity management [74] - [85]; yet, a comprehensive optimization solution is missing. The comprehensive solution should provide least cost answer while integrating increase of failure rate of transformers with age [86], their salvage value based on loss-of-life (LOL), and replacements according to economic criteria all of these at the same time.

The loadability of transformers beyond nameplate ratings and its effects of accelerated aging have been well studied [48] [49]; yet this effect has not been incorporated in the planning. References [78] and [79] proposed optimization methods for determining peak load of transformers; however, they did not perform economic analysis. The method of optimal transformer loading for maximum net benefit [80] did not consider rise in losses cost due to overloading. Only reliability cost was analyzed in [81] for decisions of optimal loading level of transformers. Reference [75] proposed a method to determine the total owning cost of transformers in which increasing failure rate of transformers along with age was included, however, it did not optimize the total cost and costs due to transformer failures. In [82] - [85], the distribution system design included substation capacity planning as well. The exceeding failure rate of transformers with age and their salvage value were not considered in [82]. References [83] - [85] assumed transformers life as a fixed value and also did not assess the reliability cost due to contingencies.

Demand response (DR) offers the benefit of cost savings in transformer capacity planning by improving the utilization efficiency over entire lifetime. This can be validated by the European Directive 2003/54/EC [87] stressing that the DR should be incorporated during planning stage of the distribution system capacity. As existing load transferring switch types (e.g., manual and remote) can have an important impact on DR based planning solution [2], [8], [88], therefore, DR and the employed switching type for load transfer to neighboring substations (NSS) should be considered abreast in the planning. The reason behind it is that the DR cannot bring load decrease for extended time as responsive appliances cannot be postponed for many hours [89] and after some time DR rebound load must be supplied.

The impact of DR in network and substation planning has not been assessed well in the literature. The focus has been on the operational planning of distribution system and transformer capacity [31], [42], [90]. The benefit of DR for reliability enhancement of distribution systems was evaluated in [29], [31], [42], [91]. Reference [92] assessed the effect of DR and automation on distribution system reliability cost. Research of [93] and [94] advocated the decrease of investment cost in transmission network capacity by employing DR at planning phases. In [95], the substation capacity planning was in combination with distribution system expansion in presence of DR, however, it did not consider transformer maintenance planning, growing failure rate with age, salvage value based on insulation loss-of-life (LOL), and load transfer to NSS during contingencies.

The above reviewed literature indicates that appropriate tools for transformer capacity planning and quantification of DR benefits in planning are needed.

4.2 Optimal Capacity Planning of Transformers

This section develops an optimization tool for capacity management of primary substation transformers over long-run. The tool determines the optimal choice of transformers' sizes, their maintenance stages, and year of transformers replacements in the planning horizon in order to minimize the present worth of total cost to supply the given load. The total cost includes costs of investment, losses, maintenance, reliability, and the salvage value of transformers. In the optimization model, rising failure rate of transformers due to aging is incorporated and the cumulative LOL of transformers is utilized in estimating their salvage value. The developed tool is applied for planning and management of transformer capacities for a typical Finnish residential two-transformer primary distribution substation over a period of forty years. The simulations are conducted for four different case studies representing the situations encountered by utilities. A broad sensitivity analysis is also performed based on various the system parameters. The numerical results indicate the significance of inclusion of variable failure rate and LOL of transformers in their capacity planning. The details of optimization model and case studies are given in the subsequent subsections.

4.2.1 Problem Formulation

Let a transformer can be installed on each transformer site at a substation from available candidates in the beginning of planning period. A new transformer from available candidates can replace the initial transformer at a later year on each site. Moreover, maintenance/refurbishment actions can be executed to reduce the failure rate of transformers. The aim is to find a set of decision variables representing transformers' selection of size, year of maintenance, and stage of replacements in the planning horizon such that the total cost is minimized for the transformers. The total cost of transformers in a substation is sum of present worth of the investment cost, the losses cost, the maintenance cost, and the interruption/reliability cost minus salvage value of investments. The optimization model is formulated as follows.

$$\text{Minimize } PWC = \sum_{a=1}^{A} (PWC_{Inv}^{a} + PWC_{Loss}^{a} + PWC_{Mai}^{a} + PWC_{Int}^{a}) - PWC_{Sal} \quad (23)$$

Where,

a and A are index of year and its maximum value, respectively.

PWC is total cost of transformers in a substation.

PWC_{Inv}^{a} denotes present worth of the investment cost at a.

PWC_{Loss}^{a} is present worth of losses cost at a.

PWC_{Mai}^{a} represents present worth of maintenance cost at a.

PWC_{Int}^{a} is present value of interruption/reliability cost at a.

PWC_{Sal} denotes present worth of salvage value of investments.

The details of each cost element are explained in the following.

Investment Cost:

The investment cost of transformers is their procurement cost that depends on their internal design and ratings. In this thesis, installation and decommissioning costs are also included in it. The investment cost of initial and replacement transformers is given by the following expressions.

$$PWC_{Inv}^{a} = C_{Inv}^{ini} = \sum_{j}\sum_{i}(C_i \cdot fb_{i,j}) \quad a = 1 \tag{24}$$

$$PWC_{Inv}^{a} = C_{Inv}^{rep} = PW^{a} \cdot \sum_{j}\sum_{i}(C_i \cdot b_{i,j}^{a}) \quad \forall a = 2,\ldots,A \tag{25}$$

$$PW^{a} = 1/(1+d)^{a-1} \quad \forall a \tag{26}$$

Where,

i, j, and a are the indices of transformer size, transformer location, and planning year, respectively.

C_i refers to the procurement cost of transformer size i.

C_{Inv}^{ini} and C_{Inv}^{rep} represent the cost of initial and replacement transformers, respectively.

$fb_{i,j}$ and $b_{i,j}^{a}$ are binary decision variables denoting the selection of a particular size transformer at each location as initial and replacement installations, respectively.

PW^{a} is the present worth factor.

d denotes the discount rate (which is based on inflation and interest rates).

Losses Cost:

Transformers' load and no-load losses depend on the material used for winding conductors and the core. The load loss is proportional to the square of transformer loading, whereas, no-load loss remains the same at all the load levels. Following equations are used to determine the losses cost.

$$PWC_{Loss}^{a} = PW^{a} \cdot \sum_{j}\sum_{LL}\begin{bmatrix}\left\{(I_{j,LL}^{a})^{2} \cdot r_{j}^{a} + NL_{j}^{a}\right\} \\ \cdot D_{LL} \cdot P_{Eng,LL}^{a}\end{bmatrix} \quad \forall t \tag{27}$$

$$\eta_{j,ini} = \sum_{i}(\eta_i \cdot fb_{i,j}) \quad \forall j \tag{28}$$

$$\eta_{j,rep} = \sum_{a=2}^{A}\sum_{i}(\eta_i \cdot b_{i,j}^{a}) \quad \forall j \tag{29}$$

$$\eta_{j}^{a} = (\gamma_{j}^{a} \cdot \eta_{j,ini} + \beta_{j}^{a} \cdot \eta_{j,rep}) \quad \forall a = 2,\ldots,A \tag{30}$$

$$b_{j}^{a} - \beta_{j}^{a} + \beta_{j}^{a-1} = 0 \quad \forall a = 2,\ldots,A \text{ and } b_{j}^{a} = \textstyle\sum_{i=1} b_{i,j}^{a} \tag{31}$$

$$-\beta_{j}^{a+1} + \beta_{j}^{a} \le 0 \quad \forall a = 2,\ldots,A-1 \tag{32}$$

$$\gamma_{j}^{a} + \beta_{j}^{a} = 1 \quad \forall a = 1,\ldots,A \tag{33}$$

Where,

i, j, a, and LL are the indices of transformer size, transformer location, planning year, and load level, respectively.

PWC_{Loss}^{a} is present worth of losses cost at a.

$I_{j,LL}^{a}$ is current of transformer at location j, load level LL, and year a.

r_{j}^{a} denotes loss equivalent resistance of transformer on j at a.

NL_{j}^{a} represents no-load loss of transformer on j at a.

D_{LL} is duration of load level LL.

$P^{a}_{Eng,LL}$ indicates energy price at LL and a.

$fb_{i,j}$ and $b^{a}_{i,j}$ are binary decision variables denoting the selection of a particular size transformer.

η_i, $\eta_{j,ini}$, and $\eta_{j,rep}$ are symbols representing the parameters (capacity, cost, resistance, and no-load of loss) of location i, initial, and replacement transformers at j.

β^{a}_{j} and γ^{a}_{j} are dependent binary variables; unity value of these indicates the replacement and initial installation of a transformer as in-service, respectively.

Equation (27) is for present worth cost of transformer losses. (28) - (33) are used to determine the parametric values of resistance and no-load loss. These values are then utilized in (27). (28) and (29) finds the values of parameters for initial and replacement transformers, respectively. The parameters of initial transformer selections are the values at the first year; however, either initial or replacement transformer can be present at later years. Therefore, (30) - (33) are utilized in order to determine the parameters of transformer installations for year 2 or later. Equations (31) - (33) guarantee that once an initial transformer is replaced by a new transformer at a location then unity value is allotted to β^{a}_{j} for all the future years.

Maintenance Cost:

Normally, the cost of maintenance activities is low [72]; however, main overhauls are of considerable cost. In this dissertation, maintenance refers to these main overhauls actions that decrease the failure rate of the transformers and is given below.

$$PWC^{a}_{Mai} = PW^{a} \cdot \sum_{j} (\phi^{a}_{j} \cdot mc^{a}_{j}) \quad \forall a \qquad (34)$$

Where,

PWC^{a}_{Mai} represents present worth of maintenance cost at year a.

ϕ^{a}_{j} is binary decision variables denoting the refurbishment of transformer at j and year a.

mc^{a}_{j} denotes maintenance cost of transformer at j and year a.

Interruption/Reliability Cost:

The expected annual cost of interruptions is estimated by considering contingencies of transformers at each location and each load level in a year. Then, calculating the interruption cost for each contingency by multiplying the failure rate, probability of load level, value of lost load, duration of load level, and unsupplied load. The formulation of interruption cost calculation is given below.

$$PWC^{a}_{Int} = PW^{a} \cdot \sum_{j} \sum_{LL} \left\{ (\lambda^{a}_{j} \cdot p_{LL} \cdot VOLL \cdot D_{LL} \cdot LNS^{a}_{j,LL} \right\} \quad \forall a \qquad (35)$$

$$LNS_{j,LL}^{a} = (L_{LL}^{a} - TEC_{j}^{a}) \cdot a_{j,LL}^{a} \quad \forall a, j, LL \qquad (36)$$
$$(L_{LL}^{a} - TEC_{j}^{a}) \cdot a_{j,LL}^{a} \geq (L_{LL}^{a} - TEC_{j}^{a}) \quad \forall a, j, LL \qquad (37)$$
$$TEC_{j}^{a} = \sum_{j', j' \neq j} (\gamma_{j'}^{a} \cdot Cap_{j',ini} + \beta_{j'}^{a} \cdot Cap_{j',rep}) \cdot ER \quad \forall a, j \; (38)$$
$$Ag_{j}^{a} = \gamma_{j}^{a} \cdot \sum_{a'=1}^{a} (\gamma_{j}^{a'} - y \cdot \phi_{j}^{a'} \cdot \gamma_{j}^{a'}) + \beta_{j}^{a} \cdot \sum_{a'=1}^{a} (\beta_{j}^{a'} - y \cdot \phi_{j}^{a'} \cdot \beta_{j}^{a'}) \; \forall a, j \quad (39)$$
$$\lambda_{j}^{a} = f(Ag_{j}^{a}) = 0.001\exp(0.0944 \cdot Ag_{j}^{a}) + 0.0169 \quad \forall a, j \quad (40) \; [96]$$

Where,

PWC_{Int}^{a} is present value of interruption/reliability cost at a.

λ_{j}^{a} represents outage rate of transformer at location j and year a.

p_{LL} denotes probability of load level LL.

D_{LL} expresses duration of load level LL.

$VOLL$ is value of lost load.

$LNS_{j,LL}^{a}$ represents load not supplied for transformer failure at location j, load level LL, and year a.

L_{LL}^{a} is load of the substation at load level LL and year a.

TEC_{j}^{a} denotes emergency capacity of healthy transformers during contingency of transformer at location j and year a.

$a_{j,LL}^{a}$ are binary variable.

$Cap_{j',ini}$, $Cap_{j',rep}$ are capacity of initial and replacement transformers at location j'.

ER is the emergency rating multiplier of transformers

Ag_{j}^{a} represents age of transformer at location j and year a.

y denotes the decrease in the equivalent age of transformer due to a maintenance action.

Equation (35) sums the interruption costs of all the transformer contingencies at each load level and weights it with the present worth factor. (36) - (38) determine the load unsupplied for transformer contingencies at each location, load level, and year. The binary variables in (36) - (37) ensure that only positive values of unsupplied load are added in the calculations. (39) and (40) find the years conceded since transformers' installation and their failure rates based on the age, respectively. The first and second summation terms in (39) are used in aging calculation of in-service transformer as initial and replacement transformer, respectively. The second term in each summation signifies the decrease in the equivalent age of transformer due to maintenance actions.

Salvage Value:

The salvage value of a transformer is its residual worth at the time of replacement/retirement or at the end of study period. It depends upon remaining life of the transformer and is calculated by the following equations.

$$\begin{aligned} PWC_{Sal} = \sum_{a=2}^{A} \left[PW^a \cdot \sum_j \left\{ b_j^a \cdot C_{j,ini} \cdot (1 - TLOL_{j,ini}) \right\} \right] \\ + PW^a \cdot \sum_j \left\{ C_j \cdot (1 - TLOL_j) \right\} \end{aligned} \tag{41}$$

$$TLOL_{j,ini} = \sum_a \left\{ \gamma_j^a \cdot \sum_i (fb_{i,j} \cdot LOL_{j,ini}^a) \right\} \tag{42}$$

$$TLOL_{j,rep} = \sum_{a=2}^{A} \sum_i (\gamma_{i,j}^a \cdot LOL_{j,rep}^a) \tag{43}$$

$$b_{i,j}^a - \beta_{i,j}^a + \beta_{i,j}^{a-1} \le 0 \quad \forall a = 2,...,A; j,i \tag{44}$$

$$-\beta_{i,j}^{a+1} + \beta_{i,j}^a \le 0 \quad \forall a = 2,...,A-1; j,i \tag{45}$$

$$\gamma_{i,j}^a = (1 - \beta_{i,j}^a) \quad \forall a,j,i \tag{46}$$

Where,

PWC_{Sal} is present worth of salvage value of investments.

$C_{j,ini}$ and C_j denote the investment cost of the initially selected transformer and the one existing at the end of the planning period at location j, respectively.

$TLOL_{j,ini}$, $TLOL_{j,rep}$, and $TLOL_j$ are the total accumulated loss-of-life over entire planning duration of transformer installations selected as initial, replacement, and the ones existing at the end of the study period, respectively.

$LOL_{j,ini}^a$ and $LOL_{j,rep}^a$ represent loss-of-life of initial and replacement transformer at location j and year a, respectively.

$\beta_{i,j}^a$ and $\gamma_{i,j}^a$ are dependent binary variables.

The first and second terms in (41) calculate the remaining life of the initial transformer installations and the ones existing at the end of study period, respectively. Clause 5 and 7 methods of [48] are employed for determining LOL of a transformer during each year a that is subsequently utilized in determining accumulated LOL of transformer in (42) - (43). Similar to (31) - (33), (44) - (46) assign the value to intermediate binary variables in order to find total LOL of optimally selected transformers.

The nonlinearities in the calculations of interruption cost and salvage value are present due to multiplication of variables and presence of exponential function. The nonlinearity of exponential function (40) is eliminated by piecewise linear approximation. And, nonlinearities due to product of variables are removed by introducing intermediate variables [97].

In addition to (31) - (33), (37), (44) - (46), and expressions for eliminating nonlinearities, the objective function (23) is subjected to the following constraints.

$$\sum_i fb_{i,j} \leq 1 \qquad \forall j \tag{47}$$

$$TLOL_{j,ini} \leq 1 \qquad \forall j \tag{48}$$

$$TLOL_{j,rep} \leq 1 \qquad \forall j \tag{49}$$

$$Ag_j^a \geq 0 \quad \forall a, j \tag{50}$$

Constraint (47) ensures that only one transformer can be selected for each site at a time. (48) and (49) limit the total LOL of initial and replacement transformers to unity. Equation (50) restricts the value of age from becoming negative due to refurbishment actions.

4.2.2 Case Studies and Results

Two-transformer site (locations) residential load dominant primary distribution substation (110 kV/20 kV) of Fig. 4.1 is considered as the test system. The transformers installed on these locations act as backup to each other during contingencies. The load profile of the substation is constructed from one year hourly measured automatic meter reading data from 1600 residential consumers from central Finland. The present peak load at the substation is assumed to be 12 MVA.

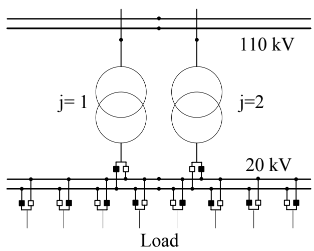

Fig. 4.1. Test system showing the location of transformers in the substation.

The load levels, their probability, and corresponding energy prices for losses and interruption cost calculations are listed in Table 4–I. Table 4–II provides the input data for similar thermal design candidate transformers. Hottest-spot rise over ambient temperature, top-oil rise, oil time constant, winding time constant, and cooling mode are 80 °C, 45 °C, 75 min, 5 min, and ONAF, respectively. Planning period is considered to be 40 years. During the whole planning horizon, load growth and discount rates values are considered to be 2.6% and 5%, respectively. The losses cost is based on the hourly electricity price data for Finland of year 2011 [98]. The average penalty of unsupplied load (VOLL) of 10 €/kWh is considered. The mixed integer linear optimization problem formulated in Section 4.2.1 is solved via the general algebraic modelling system (GAMS) environment.

TABLE 4-I

LOAD LEVELS AND CORRESPONDING ENERGY PRICE

Sr. #	Load Level (p.u.)	Probability	Energy Price (€/MWh)
1	1	0.0018	100
2	0.9	0.0061	89
3	0.8	0.0231	80
4	0.7	0.0918	68
5	0.6	0.8769	46

TABLE 4-II

PARAMETERS OF CANDIDATE TRANSFORMERS

Parameter	Transformer #1 (T1)	Transformer #2 (T2)	Transformer #3 (T3)
Nameplate ratings (MVA)	10	16	20
Investment cost (k€)	247	339	355
Maintenance cost (k€)	49	68	71
No-load loss (kW)	14.80	21.92	25.20
Load loss equivalent resistance at110 kV (Ω)	1.660	0.939	0.673
Emergency ratings (%)	120	120	120

Simulations are performed for the following case studies representing various situations encountered by utilities using the developed optimization tool.

- Case 1: Both locations have old initial transformers and sizes of transformers are known. This case designates the situation in which replacement and/or refurbishment stages of transformers are to be found while other equipment in the substation restricts the size of new transformers.
- Case 2: New transformers of specific ratings are installed in the beginning of the planning period and these can be replaced by new transformers of known sizes during the planning period. This case represents the planning situation where in-service transformers are completely aged and current transformer connected equipment restrains the rating of new transformers.
- Case 3: A transformer at one site in the substation is old while the other one is new. The ratings of the initial and replacement transformers are known. This case symbolizes the addition of a new transformer in a substation while one transformer has already been in service.
- Case 4: In this case, transformers are optimally chosen from available contenders for initial and replacement installations in the planning horizon. This condition denotes the situation of a new substation planning in which multiple transformer sizes are available and other equipment ratings will be selected based on the transformer decisions.

Besides above defined cases, a broad sensitivity analysis is also conducted for the following scenarios to examine the effect of several parameters on the results.

- Scenario 1: It is the base scenario whose results are acquired based on the input data presented in beginning of this section.
- Scenario 2: Rather than increasing failure rate with age of the transformers, constant failure rate of 0.023 [99] occurrences per year is assumed.
- Scenario 3: A variable failure rate of transformers with half the value relative to the base scenario is considered in this scenario.
- Scenario 4: A double failure rate value is assumed relative to the base scenario.
- Scenario 5: In this scenario, reduced load growth rate of 1% per year is assumed.
- Scenario 6: Relative to the base scenario, lower refurbishment impact (y=5 years) is considered here.
- Scenario 7: Lower penalty of unsupplied load (VOLL= 5 €/kWh) is considered.
- Scenario 8: In this scenario, the salvage value is incorporated only for in-service transformers at the end of the planning horizon. This scenario designates the circumstances in which transformers being replaced cannot be used at any other substation.

Case 1: Both initial transformers are old

It is assumed that the current transformers at both transformer locations (j1 and j2) in the substation are 20 years old with an expected remaining life of 50%. The ratings of the initial and replacement transformers are 10 MVA and 16 MVA, respectively. Table 4–III lists the optimal schedule of transformer replacements, maintenance years, and transformers' related costs. The optimal years of replacing initial transformers are year 13 and 16 for sites j1 and j2, respectively. Location j2 initial and replacement transformers observe normal peak loads of 0.86 p.u. and 1.02 p.u., respectively. The results of both locations are exchangeable because their size and loading are identical.

TABLE 4-III
RESULTS OF CASE 1 OBTAINED FROM PROPOSED OPTIMIZATION MODEL

Variables	Transformer location (j1)	Transformer location (j2)	Total
Net cost (k€)	762	742	1504
Investment cost (k€)	312	287	599
Loss cost (k€)	388	394	782
Maintenance cost (k€)	13	13	26
Interruption cost (k€)	168	158	326
Salvage value (k€)	119	110	229
Replacement stage (yr.)	13	16	13/16
Maintenance stage (yr.)	35	35	35/35

The total net present value of costs is €1504k, the share of investment cost, loss cost, maintenance cost, interruption cost and salvage values are €599k, €782k, €26k, €326k, and €229k, respectively. Though the failure rate of old transformers (initially in-service) is high, still overhaul is not conducted on them because of the low shortage of capacity along with small probability of transformer failure at peak load level that does not create major outage cost. The capacity shortfall during a transformer contingency at the substation at year 12 for peak load is 3.915 MW. On the other hand, the optimal year of refurbishment for the replacement transformers is year 35. The execution of these maintenances is due to substantial outage cost owing to high failure rate along with greater transformer capacity deficit during contingencies. The failure rate of transformers on j1 and j2 at year 34 are 0.0258 occurrence/year and 0.0235 occurrence /year, respectively. The capacity shortage during a transformer outage at the substation at year 39 for peak level of load is 12.626 MW.

Table 4–IV and Fig. 4.2 display the results of the sensitivity analysis. In scenarios of constant and decreased failure rates (S#1-2 and S#1-3), the renovation of transformers is not conducted because of its relatively higher cost than the saving in outage cost. The deferral in one of the transformer replacements (from year 13 to 16 in S#1-2 and to 22 in S#1-3) is also suggested in the optimal solution. The total net cost decreases in these scenarios because of low overall reliability cost and delayed transformer replacement. For the scenario of increased failure rate (S#1-4), the replacement is postponed to attain the benefit of lower failure rate near the end of the planning horizon when transformer capacity shortfall is greater. Here, the total net cost (€1640k) is higher compared to base scenario (S#1-1) due to overall high outage cost.

Peak load does not increase to higher points (maximum 8.845 MW per transformer at year 40) in lower load growth scenario (S#1-5); therefore, the initial transformers can support the load. Thus, replacement of the transformers is only desirable at the last year of the study. The refurbishments of transformers are performed (on stage 29 for j1 and 33 for j2) to decrease the failure rate of the transformers due to aging. The refurbishments decrease the failure rates of the transformer at j1 from 0.135 to 0.061 occurrence /year and from 0.193 to 0.082 occurrence /year for the transformer at j2.

In scenario of reduced effectiveness of maintenance (S#1-6), the refurbishment of transformers is not performed as its cost is higher than the associated savings in the reliability cost. Similarly, for the lower penalty of unsupplied load (S#1-7), the cost of interruption is smaller, so, refurbishment is not required and also initial transformers can supply the load for a longer time. In circumstances for which a retiring transformer cannot be used at other places (S#1-8), transformer replacements are postponed for their maximum utilization till capacity shortfall impact during contingencies surpasses the benefits of use of the old transformers.

In this case, the average portions of the costs of investment (minus salvage value), losses, maintenance, and reliability towards the total net cost are 24%, 55%, 1%, and 20% respectively.

TABLE 4-IV
SENSITIVITY ANALYSIS RESULTS FOR CASE 1

Scenario	Replacement stage (yr.)		Maintenance stage (yr.)	
	j1	j2	j1	j2
S# 1-1: Base scenario	13	16	35	35
S# 1-2: Constant failure rate	16	16	-	-
S# 1-3: Reduced failure rate	16	22	-	-
S# 1-4: Increased failure rate	15	19	35	35
S# 1-5: Reduced load growth	40	40	29	33
S# 1-6: Reduced maintenance impact	16	17	-	-
S# 1-7: Decreased VOLL	16	20	-	-
S# 1-8: Salvage of only last transformer	16	19	35	38

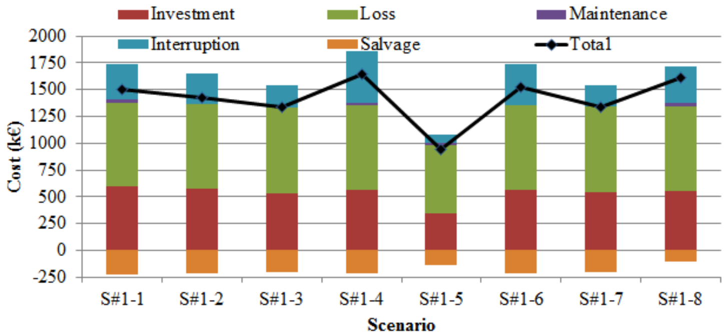

Fig. 4.2. Sensitivity analysis results for Case 1.

Case 2: Both initial transformers are new

In this case, similar ratings 10 MVA new transformers are installed at both locations (j1 and j2) in the substation at the start of the study period. Transformers of capacity 16 MVA can replace these transformers at later years. Table 4–V lists the results for this case.

TABLE 4-V
RESULTS OF CASE 2 OBTAINED FROM PROPOSED OPTIMIZATION MODEL

Variables	Transformer location		Total
	(j1)	(j2)	
Net cost (k€)	806	810	1617
Investment cost (k€)	410	418	828
Loss cost (k€)	394	392	786
Maintenance cost (k€)	13	13	26
Interruption cost (k€)	158	162	320
Salvage value (k€)	169	175	343
Replacement stage (yr.)	16	15	16/15
Maintenance stage (yr.)	35	35	35/35

Relative to Case 1, the replacement of a transformer is a bit delayed (2 years, from stage 13 to 15) due to new initial transformers. However, lower failure rate of new transformers does not have a noteworthy influence on the replacement stage as the shortfall of capacity (>9 MW) during transformer contingencies rises to a higher level after year 16. Though the reliability cost is less in this case (€320k) as compared to Case 1 (€326k), still overall cost is higher (€1504k for Case 1 and €1617k for Case 2) due to expensive new initial transformers.

Table 4–VI and Fig. 4.3 show the trend in the sensitivity study outcomes. The trend is similar to that of Case 1 for the increased failure rate (S#2-4), decreased impact of maintenance (S#2-6), and limited salvage value consideration (S#2-8). In constant failure rate scenario (S#2-2), transformer replacements are preponed to stages 11 and 13 for optimal cost and refurbishment is not required. For reduced failure rate (S#2-3), replacement plan is same but maintenance is also needed.

TABLE 4-VI
SENSITIVITY ANALYSIS RESULTS FOR CASE 2

Scenario	Replacement stage (yr.)		Maintenance stage (yr.)	
	j1	j2	j1	j2
S# 2-1	16	15	35	35
S# 2-2	11	13	-	-
S# 2-3	16	15	-	37
S# 2-4	17	16	35	35
S# 2-5	37	37	-	-
S# 2-6	16	16	-	-
S# 2-7	12	16	37	-
S# 2-8	16	19	35	35

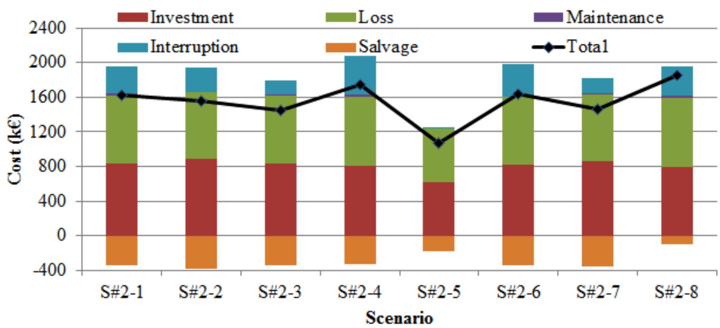

Fig. 4.3. Sensitivity analysis results for Case 2.

In case of the low load growth scenario (S#2-5), both the transformers are replaced near the end years, however, refurbishment of transformers are not recommended in the optimal solution as initial transformers were new. Furthermore, contrary to Case 1 scenario of reduced VOLL (S#1-7), one of the transformer replacements is preponed from year 15 to 12 and its overhaul is deferred from stage 35 to 37 in order to acquire the optimal economic result.

Average shares of the costs of investment (minus salvage value), losses, maintenance, and reliability in the total net cost of this case are 33%, 49%, 1%, and 17% respectively. Compared to Case 1, the percentage of investment cost is greater here due to higher cost of a new initial transformer and reliability cost is a bit lesser because of smaller failure rate of new transformers.

Case 3: One of the initial transformers is old

Here, initial transformers of capacity 10 MVA each at location j1 and j2 in the substation can be substituted by 16 MVA transformers. The transformer at location j1 is 20 years old with remaining life of 50% whereas rest of the transformers is new. The results of this scenario are presented in Table 4–VII.

The present value of total cost in this case is €1555k, the share of cost at location j1 (€739k) is less than at j2 (€816k) due to old (lower investment cost) initial transformer installation at j1. The optimal replacement years of transformers at locations j1 and j2 are 17 and 14, respectively. The higher rating replacement transformer at j2 permits the delay of replacement at j1 because during contingencies of the transformer at j1, the capacity of j2 transformer is sufficient to supply the entire load of the substation. The refurbishment of the replacement transformers at stage 35 is performed to reduce the interruption cost value by decreasing failure rates of transformers. The key difference between total net cost of this case with Cases 1 and 2 is due to difference in investment cost of initial transformers due to their age.

TABLE 4-VII
RESULTS OF CASE 3 OBTAINED FROM PROPOSED OPTIMIZATION MODEL

Variables	Transformer location (j1)	Transformer location (j2)	Total
Net cost (k€)	739	816	1555
Investment cost (k€)	279	426	705
Loss cost (k€)	396	390	786
Maintenance cost (k€)	13	13	26
Interruption cost (k€)	157	168	326
Salvage value (k€)	107	181	288
Replacement stage (yr.)	17	14	17/14
Maintenance stage (yr.)	35	35	35/35

Table 4–VIII and Fig. 4.4 present the results of the sensitivity analysis. Because of reduced failure rate in scenario S#3-3, the replacement of the old transformer at j1 and refurbishment of the transformer at j2 are postponed to stages 19 and 37, respectively. In order to keep the new transformer (at j2) for an extended duration in scenario of no salvage value of retiring transformer (S#3-8), the old transformer (at j1) replacement with a higher rating transformer (16 MVA) is preponed so that capacity deficits during j2 contingencies is smaller. The trend in results for the other scenarios (S#3-2, S#3-4, S#3-5, S#3-6, S#3-7) are similar to as in Case 2.

In this Case, the average segments of cost of investment (minus salvage value), losses, maintenance, and interruption in the total net cost of this case are 29%, 52%, 1%, and 18% respectively, which are in between the results of Case 1 and Case 2.

TABLE 4-VIII
SENSITIVITY ANALYSIS RESULTS FOR CASE 3

Scenario	Replacement stage (yr.)		Maintenance stage (yr.)	
	j1	j2	j1	j2
S# 3-1	17	14	35	35
S# 3-2	13	16	-	-
S# 3-3	19	14	-	37
S# 3-4	17	15	35	35
S# 3-5	27	37	-	-
S# 3-6	17	16	-	-
S# 3-7	16	13	-	37
S# 3-8	13	18	32	37

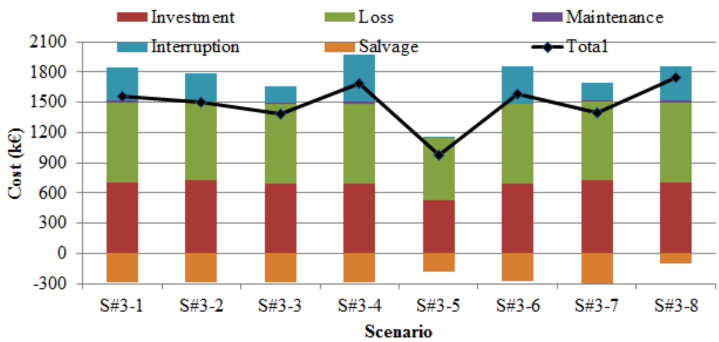

Fig. 4.4. Sensitivity analysis results for Case 3.

Case 4: Optimal selection of all transformer installations

In this case, the optimal size selection of initial and replacement (if needed) transformers for both the sites (j1 and j2) from available contenders are found. The choices of transformers sizes, their replacement years, maintenance stages, and associated costs determined by the model of Section 4.2.1 are given in Table 4–IX.

It is cost effective to install 10 MVA transformers at both the locations at start of planning and replace them with 20 MVA transformers at year 12. These decisions are such that the interruption cost is small (€5k). The major share of investment cost (€909k) is recovered in form of salvage value (€394k) as the load on the transformers remains moderate (maximum 0.78 p.u. for 10 MVA transformers and 0.82 p.u. for 20 MVA transformers) resulting into insignificant LOL of transformers. The losses cost (€714k) constitutes a major share of total cost (€1234k). The transformers at each location create equal slice towards the total net cost.

TABLE 4-IX
RESULTS OF CASE 4 OBTAINED FROM PROPOSED OPTIMIZATION MODEL

Variables	Transformer location (j1)	Transformer location (j2)	Total
Rating of initial transformer (MVA)	10	10	10/10
Rating of replacement transformer (MVA)	20	20	20/20
Net cost (k€)	617	617	1234
Investment cost (k€)	454.5	454.5	909
Loss cost (k€)	357	357	714
Maintenance cost (k€)	-	-	-
Interruption cost (k€)	2.5	2.5	5
Salvage value (k€)	197	197	394
Replacement stage (yr.)	12	12	12/12
Maintenance stage (yr.)	-	-	-

Table 4–X and Fig. 4.5 exhibit the sensitivity study results. The variations of failure rate, impact of maintenance, and VOLL (S#4-2, 4-3, 4-4, 4-6, and 4-7) do not alter the decisions of transformer sizes and schedules because of low outage cost due to specific optimal decisions of transformer sizes and their replacement. In the scenario of lower load growth (S#4-5), 10 MVA transformers operation for a longer duration (till year 24) and a smaller size (16 MVA) for the replacement at j1 are recommended due to overall low demand peaks. It is advantageous to choose the higher rating (20 MVA) initial transformers in S#4-8, so that the replacement transformer is not required. Also overhaul of transformers (for j1 at stage 15 and j2 at stage 22) is needed to decrease the failure rate of the transformers due to aging.

Average percentages of the costs of investment (minus salvage value), losses, maintenance, and reliability in the total net cost of this case are 42%, 57%, 0.6%, and 0.4%, respectively. Here, the part of reliability cost is very low because all transformer sizes along with their replacement stages are optimally selected.

TABLE 4-X
SENSITIVITY ANALYSIS RESULTS FOR CASE 4

Scenario	Replacement stage (yr.)		Maintenance stage (yr.)		Initial transformer (MVA)		Replacement transformer (MVA)	
	j1	j2	j1	j2	j1	j2	j1	j2
S# 4-1	12	12	-	-	10	10	20	20
S# 4-2	12	12	-	-	10	10	20	20
S# 4-3	12	12	-	-	10	10	20	20
S# 4-4	12	12	-	-	10	10	20	20
S# 4-5	24	24	-	-	10	10	16	20
S# 4-6	12	12	-	-	10	10	20	20
S# 4-7	12	12	-	-	10	10	20	20
S# 4-8	-	-	15	22	20	20	-	-

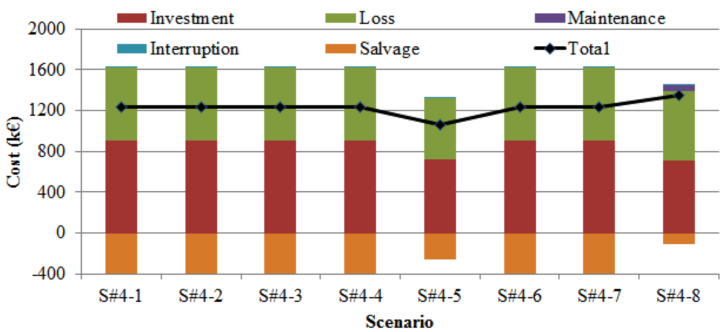

Fig. 4.5. Sensitivity analysis results for Case 4.

4.3 Demand Response Benefit for Capacity Planning of Transformers

In the preceding section, a transformer optimal capacity planning tool was developed. This section modifies that tool to add the features of DR and NSS capacity support. The optimization model of the tool incorporates the DR as a resource to reduce the outage cost during contingencies while considering existing switching types for load transfer between substations. Like the tool of the previous section, this model yields the optimal selection and scheduling of multistage transformer installations and their overhauls by considering all the costs related to them including investment, losses, maintenance, reliability, and the salvage value. For quantification of DR benefits, the numerical value of the savings in transformers' cost by DR is calculated for a typical Finnish two-transformer primary distribution substation planning over a period of forty years. Case studies are conducted based on situations encountered by utilities and type of load transfer switching (manual and remote) between substations. A sensitivity analysis based on DR penetration and load curtailment (LC) cost is also executed. The results exhibit the worth of DR and network automation in optimal substation transformer capacity planning.

4.3.1 Problem Formulation

The goal of the revised tool is also to determine a set of decision variables designating transformers' selection of ratings and stage of maintenance and replacements in the planning horizon such that the total cost is optimal for the transformers. The optimization model for the modified tool is same as of the basic tool except the difference in the interruption/reliability cost formulation. During the contingencies of transformers, overload on healthy transformers can be relieved by optimally activating DR, shifting load to NSS (if there is free capacity), and/or LC. The formulation devised in Section 4.2.1 for objective function, investment cost, losses cost, maintenance cost, and salvage value are applicable here as well. The following subsection presents only the modified interruption cost formulation in order to incorporate DR and network automation feature in the model.

Interruption/Reliability Cost:

The present worth of expected interruption cost depends upon transformers' instance of failure, failure rate, load curtailed, and DR activated. It is calculated by considering contingencies of transformers at each location in a year and by adding the costs of load curtailment and DR actions. The formulation comprises of the following expressions.

$$PWC_{Int}^{a} = PW^{a} \sum_{j} \sum_{h} \left\{ \begin{array}{l} (\lambda_j^a / 8760) \cdot \\ \sum_{z=h}^{h+Tr} (c_{LC} \cdot LC_{j,a,h}^{z} + c_{DR} \cdot DR_{j,a,h}^{z}) \end{array} \right\} \quad (51)$$

$$P_{j,a,h}^{z} \leq TEC_j^a \quad \forall z < h + h_{sw} \quad (52)$$

$$P_{j,a,h}^{z} \leq TEC_j^a + \mathrm{NSS}^a \quad \forall z \geq h + h_{sw} \quad (53)$$

$$TEC_j^a = \sum_{j'=1, j' \neq j} (\gamma_{j'}^{a} \cdot Cap_{j',ini} + \beta_{j'}^{a} \cdot Cap_{j',rep}) \cdot ER \quad (54)$$

$$P_{j,a,h}^{z} = P_{DR}^{a,z} + P_{C}^{a,z} + \sum_{z''} DR_{j,a,h}^{z'',z} - LC_{j,a,h}^{z} - \sum_{z'} DR_{j,a,h}^{z,z'} \quad (55)$$

$$0 \leq LC_{j,a,h}^{z} \leq P_{DR}^{a,z} + P_{C}^{a,z} + \sum_{z''} DR_{j,a,h}^{z'',z} - \sum_{z'} DR_{j,a,h}^{z,z'} \quad (56)$$

$$\sum_{z'} DR_{j,a,h}^{z,z'} \leq \sum_{z'} P_{DR}^{a,z,z'} \quad \forall\ z' \in z + \{1, 2, ..., T_{DR}^{\max}\} \quad (57)$$

$$DR_{j,a,h}^{z} = \sum_{z'} DR_{j,a,h}^{z,z'} \quad \forall z' \in z + \{1, 2, ..., T_{DR}^{\max}\} \quad (58)$$

$$Ag_j^a = \gamma_j^a \cdot \sum_{a'=1}^{a} (\gamma_j^{a'} - y \cdot \phi_j^{a'} \cdot \gamma_j^{a'}) + \beta_j^a \cdot \sum_{a'=1}^{a} (\beta_j^{a'} - y \cdot \phi_j^{a'} \cdot \beta_j^{a'}) \quad (59)$$

$$\lambda_j^a = f(Ag_j^a) = 0.001 \exp(0.0944 \cdot Ag_j^a) + 0.0169 \quad (60)$$

Where,

j and j' are the indices of transformer location.

h, z, z', and z'' are the indices of the hour in a year.

a and a' are the indices of year.

PWC_{Int}^{a} is present value of interruption/reliability cost at a.

PW^{a} is the present worth factor.

λ_j^a represents the outage rate of a transformer at location j and year a.

T_r is repair duration for transformers.

c_{LC} represents the unit load curtailment cost.

c_{DR} denotes the unit incentive paid to the customer for using their DR flexibility.

$LC_{j,a,h}^{z}$ is a linear variable for load curtailment.

$DR_{j,a,h}^{z}$ represents a linear variable for demand deferred.

$P_{j,a,h}^{z}$ is modified load profile after overload relieving actions.

TEC_j^a denotes the emergency capacity of healthy transformers during a contingency of transformer at location j and year a.

NSS^a is neighboring substation capacity at year a.

h_{sw} is switch time parameter whose value depends upon the type of load transfer (i.e., manual or remote) between substations.

$\beta_{j'}^a$ and $\gamma_{j'}^a$ are dependent binary variables; unity value of these indicates the replacement and initial installation of a transformer as in-service, respectively.

$Cap_{j',ini}$, $Cap_{j',rep}$ are the capacity of initial and replacement transformers at location j'.

ER is the emergency rating multiplier of transformers.

$DR_{j,a,h}^{z'',z}$ represents load deferred to z in prior times z'' (DR load recovery) linear variable.

$DR_{j,a,h}^{z,z'}$ and $P_{DR}^{a,z,z'}$ are linear variable for load deferred from hour z to later hour $z'$and its peak bound, respectively.

$T_{DR}^{\max}$ denotes the maximum time for which a load can be deferred.

Ag_j^a represents age of transformer at location j and year a.

Equation (51) calculates the expected interruption cost of transformers by considering each location transformer failure at each hour of the year and summing the multiplications of unit LC cost with the amount of demand curtailed and unit DR activation cost with the amount of demand delayed during repair time of the transformer. The cost is subsequently weighted by the probability of outage of the transformer at the given hour of the year and present worth factor. (52) - (58) determine the decision variables of LC and DR activation. The constraints (52) and (53) limit the modified load profile post LC and DR activation to be within the defined capacity bounds. During switching (52), only available transformers' capacity is emergency load carrying capacity of healthy transformers in the substation. Whereas, NSS capacity is also accessible to supply the load after switching times (53). Equation (54) finds the total emergency capacity of the same substation which is the product of emergency rating multiplier of transformers and sum of capacity of healthy transformers. The modified load profile during a contingency found by (55) is the sum of available flexible load, critical load, load deferred in prior times minus load curtailed and load deferred to later times. Constraint (56) bounds the LC value. (57) limits the DR activation to the power available under DR contract. Equation (58) calculates the total load deferred under DR by adding the loads postponed to all possible future hours. (59) and (60) are for computing age and failure rates of transformers, respectively, like (39) and (40).

In order to keep the optimization problem to mixed integer quadratic programming problem, the nonlinearity of exponential function (60) is removed by piecewise linear approximation. And, higher order nonlinearity due to products of binary variables in (59) are removed by introducing intermediate variables [97].

4.3.2 Case Studies and Results

The two transformer location substation as used in Section 4.2.3 is also considered as the test system here, with the following difference/additional information. The substation is supplying power to an area mix of residential and commercial load and current peak demand is about 14 MVA. The neighboring substation support of 6 MW is also available that requires 3h and 1h for load transfer by manual and remote switching, respectively. The average penalty of LC for critical load and cost of load adjustment under DR are assumed to be 15 €/kWh [100] and 0.20 €/kWh, respectively.

To demonstrate the application of the developed tool in quantification of the DR benefits and automation impact on substation transformers capacity planning, results for the following case studies are described.

- Case 1: Initial transformers at both locations in the substation are old. Also, the sizes of initial and replacement transformers are known. This case characterizes the typical situation confronted by utilities in which replacement and/or refurbishment years of transformers are to be decided while other equipments in the substation restrict the size of replacement transformer. Load relocation to NSS during contingencies by manual switches is supposed here.
- Case 2: All the settings are same as that of Case 1 except that the load shifting to NSS is accomplished by remotely controlled switches.
- Case 3: In this case, all transformer sizes are optimally chosen from available candidates for initial and subsequent installations in the planning horizon. This condition represents the situation of a new substation planning in which a number of transformers are available and other equipment ratings will be decided based on the transformer choices. Here, it is considered that the load shifting to NSS during outages is performed by manual switches.
- Case 4: All the settings are the same as Case 3 except that the load transfer to NSS is achieved via remote controlled switches.

Additionally, a sensitivity study is also conducted for the following scenarios to examine the effect of penetration of DR technology and price of LC on the results of the case studies.

- Scenario 1: This is the base scenario whose results are obtained by using input data presented in the beginning of this subsection and assuming 100% DR penetration (all the flexible customers are responsive).
- Scenario 2: DR penetration is assumed to be 50% (only 50% of the flexible customers are

responsive) in this scenario.

- Scenario 3: Here, load is considered unresponsive. This case renders the base for comparison of the DR benefit.
- Scenario 4: The decreased penalty of LC (7.5 €/kWh) is assumed in this scenario.
- Scenario 5: In this scenario, double LC penalty (30 €/kWh) as compared to the base scenario is considered.

Case 1: Old initial transformers and manual switching

It is assumed that the initial transformers (10 MVA each) at both transformer locations (j1 and j2) in the substation are 20 years old with an expected remaining life of 50%. A new replacement transformer of size 16 MVA is to be installed at each location in the study period. It is considered that all the flexible customers are responsive (100% DR penetration) and switching of load transfer to NSS is manual. The optimum schedule of transformer replacements, refurbishment years, and transformers' related costs computed by the proposed tool are presented in Table 4–XI.

TABLE 4-XI
RESULTS OF CASE 1 OBTAINED FROM PROPOSED OPTIMIZATION MODEL

Variables	Transformer location (j1)	(j2)	Total
Net cost (k€)	824.8	829.8	1654.6
Investment cost (k€)	278.7	294.7	573.4
Loss cost (k€)	582.6	572.9	1155.5
Maintenance cost (k€)	-	-	-
Interruption cost (k€)	70.3	74.8	145.1
Salvage value (k€)	106.8	112.6	219.4
Replacement stage (yr.)	17	15	17/15
Maintenance stage (yr.)	-	-	-/-

The optimal years of replacing old transformers are years 17 and 15 for locations j1 and j2, respectively. The peak demands observed by initial and replacement transformers for normal conditions on location j1 are 1.08 p.u. and 1.19 p.u., respectively. The total net present value of costs is €1654.6k, out of which the percentages of investment minus salvage, loss, maintenance, and reliability costs are around 21%, 70%, 0%, and 9%, respectively.

Though the failure rate of initial transformer is high, yet maintenance is not performed on them because compound impact of small probability of transformer failure at peak load and activation of DR retains the interruption cost to a low level. The capacity shortfalls during peak load transformer outage at year 14 before and after load shifting to NSS with manual switches are 7.5 MW and 1.5 MW, respectively. The LC and DR needed to maintain the load within transformer limits for a contingency at this level are 16 MWh and 25 MWh, respectively. The probable interruption cost (probability of transformer failure is 0.00029) at this peak load is €72 which is very low. The low interruption cost compared to the total cost is because of activation of DR. The low interruption cost also evades the refurbishments of replacement transformers, even though capacity shortage for peak load contingency at year 39 is substantial (18 MW).

Table 4–XII and Fig. 4.6 provide the sensitivity assessment results. The replacement and maintenance program do not change for 50% DR penetration (S#1-2); however, rise in interruption cost is due to greater requirement of LC because of reduced DR capability. Nonexistence of DR in S#1-3, prepones the schedule of replacements (to years 16 and 13) and involves refurbishment of transformer of j1 at year 34 for the best solution. In this scenario, the total cost is higher relative to DR scenarios. In scenario of reduced LC penalty (S#1-4), total cost decreases due to decline in reliability cost, however, replacement years remain same as of S#1-1. For increased LC penalty (S#1-5), one of the transformers replacement is preponed (from year 15 to 12 at j2) and both replacements require maintenance (at year 33) to provide optimal economic solution by retaining the reliability cost at a reasonable level.

TABLE 4-XII
SENSITIVITY ANALYSIS RESULTS FOR CASE 1

Scenario	Replacement stage (yr.)		Maintenance stage (yr.)	
	j1	j2	j1	j2
S# 1-1: Base scenario	17	15	-	-
S# 1-2: 50% DR penetration	17	15	-	-
S# 1-3: No DR	16	13	34	-
S# 1-4: Decreased LC penalty	17	15	-	-
S# 1-5: Increased LC penalty	17	12	33	33

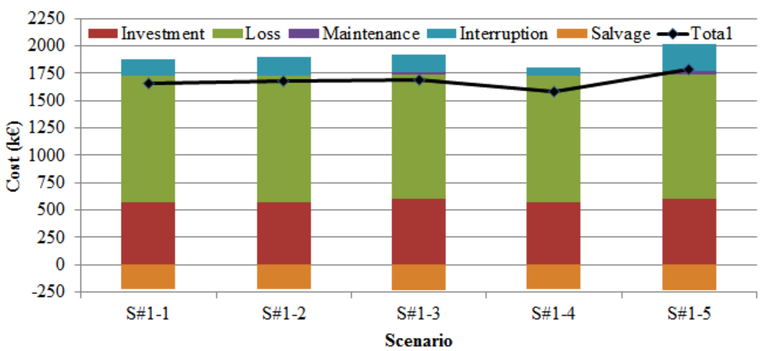

Fig. 4.6. Sensitivity analysis results for Case 1.

Case 2: Old initial transformers and remote switching

All the conditions are considered same as of Case 1 in here except that remote controlled switches are available for load transfer between substations. Table 4–XIII shows the results for this case.

TABLE 4-XIII

RESULTS OF CASE 2 OBTAINED FROM PROPOSED OPTIMIZATION MODEL

Variables	Transformer location		Total
	(j1)	(j2)	
Net cost (k€)	810.9	811.8	1622.7
Investment cost (k€)	271.3	278.7	550
Loss cost (k€)	587.6	582.6	1170.2
Maintenance cost (k€)	-	-	-
Interruption cost (k€)	56.1	57.3	113.4
Salvage value (k€)	104.1	106.8	210.9
Replacement stage (yr.)	18	17	18/17
Maintenance stage (yr.)	-	-	-/-

The total net present value of costs is €1622.7k, out of which the shares of investment cost minus salvage, loss cost, maintenance cost, and reliability cost are 21%, 72%, 0%, and 7%, respectively. Here, the interruption cost part is a bit lower than that of Case 1 due to quick shifting of load to NSS. Therefore in the result, the replacement schedule is a bit deferred (for j1 from year 17 to 18 and for j2 from year 15 to 17) as compared to Case 1. DR and LC requirements for peak demand contingency at year 14 are 4 MW and 36 MW, respectively. Probable reliability cost (probability of transformer contingency is 0.00029) at this level is €18 which is comparatively lesser than that of Case 1.

Table 4–XIV and Fig. 4.7 display the similar trend in sensitivity study for this case as of Case 1. In lower DR penetration scenarios (S#2-2 and S#2-3), one of the transformer replacements is preponed and total cost is higher due to increased reliability cost. The least overall cost in S#2-4 is due to the lowest LC penalty. For higher LC penalty (S#2-5), replacement times are unchanged, however, transformer overhauls are also needed to reduce the interruption cost close to end years.

TABLE 4-XIV

SENSITIVITY ANALYSIS RESULTS FOR CASE 2

Scenario	Replacement stage (yr.)		Maintenance stage (yr.)	
	j1	j2	j1	j2
S# 2-1	18	17	-	-
S# 2-2	17	16	-	-
S# 2-3	17	15	-	-
S# 2-4	17	17	-	-
S# 2-5	18	17	34	34

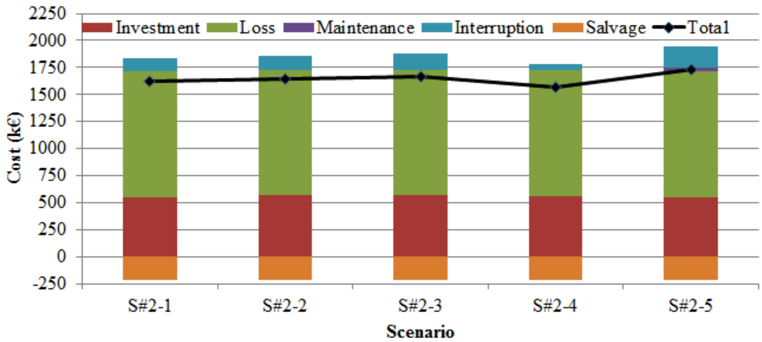

Fig. 4.7. Sensitivity analysis results for Case 2.

Case 3: Optimal selection and manual switching

This case selects all the transformer ratings from available candidates by using the developed tool. Full DR penetration and manual transfer of load between substations are considered here. Table 4–XV lists the results of transformer ratings, their replacement years, maintenance schedules, and associated costs. The optimal size of initial and replacement transformers are 10 MVA and 20 MVA, respectively. The corresponding replacement year is 6. The share in costs by transformers at both locations is the same. The fragments of the costs of investment (minus salvage value), losses, maintenance, and reliability in the total cost (€1525.2k) are approximately 36%, 62%, 0%, and 2%, respectively. The selection of transformers and their replacement plan is such that the total interruption cost is very low (€27k) with the backing of DR. The normal peak demands supplied by initial and replacement transformers (0.78 p.u. for 10 MVA transformers and 0.95 p.u. for 20 MVA transformers) are also rational.

TABLE 4-XV
RESULTS OF CASE 3 OBTAINED FROM PROPOSED OPTIMIZATION MODEL

Variables	Transformer location		Total
	(j1)	(j2)	
Rating of initial transformer (MVA)	10	10	10/10
Rating of replacement transformer (MVA)	20	20	20/20
Net cost (k€)	762.6	762.6	1525.2
Investment cost (k€)	525	525	1050
Loss cost (k€)	470	470	940
Maintenance cost (k€)	-	-	-
Interruption cost (k€)	13.5	13.5	27
Salvage value (k€)	245.9	245.9	491.8
Replacement stage (yr.)	6	6	6/6
Maintenance stage (yr.)	-	-	-/-

The results of the sensitivity inquiry are exhibited in Table 4–XVI and Fig. 4.8. In scenarios of reduced DR penetration and increased LC penalty (S#3-2, S#3-3, and S#3-5), it is advantageous to install higher rating transformers (20 MVA) initially to achieve best solution. In these scenarios, larger transformer sizes enable the deferment of replacements. Here, total cost is higher than that of base scenario. In order to reduce the reliability cost for DR less scenario (S#3-3), overhauls of transformers are also needed at year 11. Transformer choices are same in reduced LC penalty (S#3-4); however, replacements are preponed by one year for optimal economical cost.

TABLE 4-XVI
SENSITIVITY ANALYSIS RESULTS FOR CASE 3

Scenario	Replacement stage (yr.)		Maintenance stage (yr.)		Initial transformer (MVA)		Replacement transformer (MVA)	
	j1	j2	j1	j2	j1	j2	j1	j2
S# 3-1	6	6	-	-	10	10	20	20
S# 3-2	29	2	-	-	20	20	20	20
S# 3-3	13	13	11	11	20	20	20	20
S# 3-4	5	5	-	-	10	10	20	20
S# 3-5	7	7	-	-	20	20	20	20

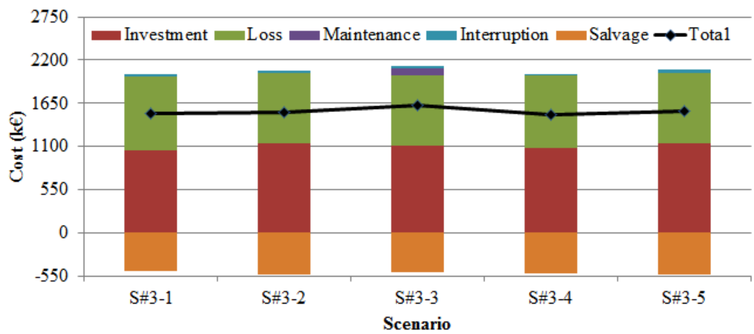

Fig. 4.8. Sensitivity analysis results for Case 3.

Case 4: Optimal selection and remote switching

The sole difference in this case compared to Case 3 is the remote switches instead of manual ones for load shifting among substation during contingencies. The investigation of results (Table 4–XVII) indicates that the transformer ratings and their replacement schedule are same as of Case 3; however, small decrease in overall cost is due to reduction in interruption cost due to faster switches. The portions of cost of investment (minus salvage value), losses, maintenance, and reliability in the total net cost of this case are around 37%, 62%, 0%, and 1%, respectively.

Table 4–XVIII and Fig. 4.9 demonstrate the sensitivity study results. In this case, the selection of transformers is identical to that of Case 3. However, slight postponement in replacement of

transformers in S#4-2 and S#4-5 is due to small load transfer switching times that result into lower reliability costs.

TABLE 4-XVII
RESULTS OF CASE 4 OBTAINED FROM PROPOSED OPTIMIZATION MODEL

Variables	Transformer location (j1)	Transformer location (j2)	Total
Rating of initial transformer (MVA)	10	10	10/10
Rating of replacement transformer (MVA)	20	20	20/20
Net cost (k€)	758.8	758.8	1517.6
Investment cost (k€)	525	525	1050
Loss cost (k€)	470	470	940
Maintenance cost (k€)	-	-	-
Interruption cost (k€)	9.7	9.7	19.4
Salvage value (k€)	245.9	245.9	491.8
Replacement stage (yr.)	6	6	6/6
Maintenance stage (yr.)	-	-	-/-

TABLE 4-XVIII
SENSITIVITY ANALYSIS RESULTS FOR CASE 4

Scenario	Replacement stage (yr.)		Maintenance stage (yr.)		Initial transformer (MVA)		Replacement transformer (MVA)	
	j1	j2	j1	j2	j1	j2	j1	j2
S# 4-1	6	6	-	-	10	10	20	20
S# 4-2	35	2	-	-	20	20	20	20
S# 4-3	13	13	11	11	20	20	20	20
S# 4-4	5	5	-	-	10	10	20	20
S# 4-5	8	8	-	-	20	20	20	20

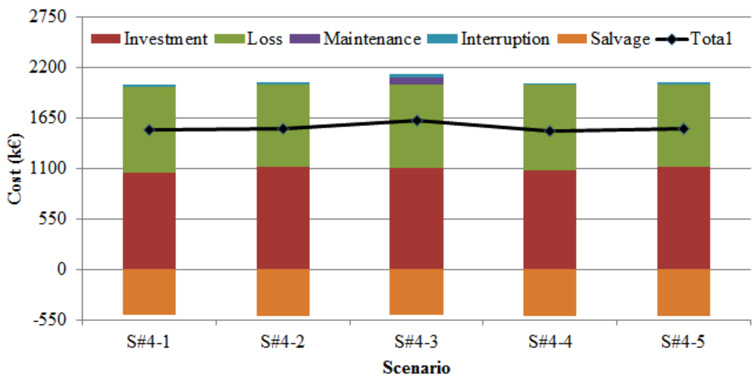

Fig. 4.9. Sensitivity analysis results for Case 4.

Table 4–XIX summarizes the comparison of total cost between Scenarios 1 and 3 for all the cases. It is convenient in evaluating the benefit of DR in transformer capacity planning. The gains of DR for Cases 1, 2, 3 and 4 are €38.6k, €40.5k, €98.6k, and €101.3k, respectively. The DR benefit is comparatively superior for cases in which load to NSS is shifted by remote switching than the cases of manual shifting. This difference in benefit based on type of switches

would be greater for systems in which manual shifting takes longer times. The main decrease in load using DR is required immediately following a contingency while load shifting to NSS is being organized. DR is needed for short times in Case 2 and Case 4 owing to remote switching, consequently, higher load reduction can be achieved. Whereas in Case 1 and Case 3, DR is required for longer duration because of manual switches. The load payback phenomenon declines the load reduction ability in these cases. Therefore, the use of DR is relatively more advantageous for cases of load transfer to NSS via remote switches.

TABLE 4-XIX
DR BENEFIT COMPARISON FOR CASE STUDIES

Case	Total cost (k€)		DR benefit
	Scenario 1: 100% DR	Scenario 3: No DR	(k€)
Case 1	1654.6	1693.2	38.6
Case 2	1622.7	1663.2	40.5
Case 3	1525.2	1623.8	98.6
Case 4	1517.6	1618.9	101.3

4.4 Conclusion

The proficient capacity management of transformers in substations is critical for an economic power system due to their high cost. This chapter devised the tools for capacity management of transformers in a primary distribution substation. At first, an optimization tool was developed for transformer capacity planning for long-run considering the all the associated costs and features of growing failure rate and salvage value. Secondly, a modified tool was created to add the feature of DR. Using both the tools, transformer capacity management problem was solved for various situations faced by utilities in planning a typical Finnish primary substation. Broad sensitivity analyses were also conducted to demonstrate the influence of various parameters on the results. The results of studies indicated the value of the tools in transformer capacity management. The investigation revealed that DR can offer considerable economic benefits in transformer capacity planning and these benefits are superior for systems in which remote switches are used for load transfer between substations. The utilities can utilize these tools for planning of transformer ratings, their replacement and maintenance scheduling, and decisions of DR deployments.

5 Demand Response Benefit for Sub-transmission Networks

The last two chapters studied the benefits of demand response (DR) for transformers only. This chapter evaluates the potential of DR for redundancy mitigation in sub-transmission networks (considering lines, transformers, and busbars). After an introductory section, system Markov models for contingencies of various components of sub-transmission systems are developed. Afterwards, an evaluation framework is presented for calculating the outage cost. Then, case studies are presented for a typical Finnish system to assess the DR benefits. Conclusion of the chapter follows at the end.

5.1 Introduction and Literature Review

Sub-transmission networks are the important link between transmission and distribution systems. Their sufficient capacity and efficient utilization is vital for an economic and reliable delivery of supply. Random failures in networks produce outage cost losses that are inversely dependent upon redundancy design. Most utilities design their network to a definite contingency level, e.g., N-1, which specifies no loss of supply due to lack of capacity following single contingency [101]. The design logic of N-1 or higher contingencies might lead to overinvestments as load factor of demand is usually low and contingencies are not frequent [102]. Furthermore, owing to load growth, limited available capacity, and costly and tedious nature of sub-transmission system expansions, novel solutions are required by utilities to supply the load efficiently. DR can offer the savings in sub-transmission network capacity by providing support during contingencies, thus, releasing the redundant capacity that can be used for normal operations.

Despite a rigorous research on DR benefits for distribution networks, its influence on sub-transmission networks has not been studied well. The focus has been on the distribution system [29], [31], [34], [42], [90], [92], [95]. References [93] and [94] proposed the models for assessment of price-based and event-based DR benefits in transmission network planning, respectively. In [102], the benefit of curtailable load for network investment was determined by comparing the annuitized present worth of future network investment, with and without curtailable load, to supply the load during network failures. However, it did not carry out the probabilistic reliability analysis for network failures.

In the following, the potential of DR in alleviating the redundancy requirements of sub-transmission system is evaluated by considering DR as a redundancy substitute which is triggered by network contingencies. The comparison of outage cost for future demand is adopted as an evaluation methodology; this comparison is between non-investing in the network and use of DR as a redundancy resource. In order to find the outage cost, novel Markov models are developed for system states during various components' contingencies (lines, transformers, and busbars) in presence of DR. Using the developed models and an outage cost comparison methodology, DR benefit assessment is performed for a typical Finnish sub-transmission network.

5.2 System Models for Components' Faults

This section proposes system Markov models for contingencies of considered components. The components considered are HV lines, HV busbars and HV/MV transformers.

Markov models portraying states of a system for a contingency can be simply comprised of two [103] or three states [104] - [107]. These states characterize the operations of normal working (up) and failure/down (switching and restoration). The detailed modelling of switching and restoration actions requires n+2 state Markov model as proposed in [108] where failure (down) state is divided into multiple states. In [108], the transition rate from any down state to up state is assumed constant; which can only be true if switching rates for transferable loads are very small compared to repair time of the considered component. This is not always valid, e.g., shifting of load to a neighboring substation involves switching re-arrangement which may take significant time. Another weakness of the model is that it does not fulfill the following condition; for a certain load and capacity of network, if the system has to enter a specific down state then the transition rate from all earlier down states to up state should be zero.

Another generalized n+2 state Markov model for a station oriented reliability assessment was proposed in [109] and [110]. Where switching actions at a station are distributed into multiple steps, such that restoration of each line or feeder is denoted by a different state. That model is not valid in circumstances where repair of defective component and switching actions to restore disconnected load are performed at the same time (independent but non-mutually exclusive). Here [VI], novel pseudo-Markov models are developed to increase the accuracy of reliability indices for sub-transmission contingencies and to incorporate DR. At first, models are developed without considering DR, and then they are modified to include DR impact. These models imitate real operational features and produce improved results for situations where switching times are not very short, and repair and switching may be non-mutually exclusive. In proposed pseudo-Markov models transition times between states are acquired by manipulating mean repair and switching times and it is supposed that calculated transition times between states are distributed exponentially thus obey the Markovian property (transition rate independent of time) [111] - [112].

Proposed Basic Models: Without DR

Firstly, the basic system state models are drawn for the faults of components without considering DR.

A) HV lines:

Basic system state model for HV line faults is shown in Fig. 5.1. The details of the states are given in the following.

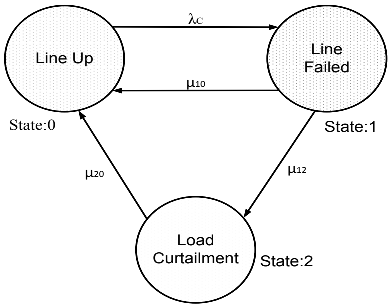

Fig. 5.1. Basic system state model for HV line faults.

State 0: Up state denotes that all segments are working.

State 1: Failed state indicates that one of the line sections is in a failed state. Transition from state '0' to state '1' depends on fault rate (λ_c) of lines. Sufficient capacity of remaining network results into transition back to up state after repair.

State 2: Load curtailment (LC) state. A shortage of remaining network capacity during contingency leads to this state. During transition to this state, healthy lines are permitted to carry load up to short-term emergency rating in state '1'.

The transition rates between states are conditional and equal to reciprocal of transition times as given below.

$$\mu_{10} = \begin{cases} 1/T_r & \text{If LC not needed.} \\ 0 & \text{else} \end{cases} \tag{61}$$

$$\mu_{12} = \begin{cases} 1/T_{LC} & \text{If LC needed.} \\ 0 & \text{else} \end{cases} \tag{62}$$

$$\mu_{20} = 1/(T_r - T_{LC}) \tag{63}$$

Where,

μ_{uv} represents transition rate from state u to v.

T_r is time required to repair and re-connect component (including detection and isolation).

T_{LC} denotes load curtailment time.

B) HV/MV transformers:

For a HV/MV transformer contingency, the reserve capacity may be available in the same or in a neighboring substation (NSS). In case reserve capacity of transformer in the same substation is not adequate to supply the entire demand then after switching re-arrangement partial load can be transferred to a neighboring substation transformer. Fig. 5.2 depicts the system model for a transformer contingency where reserve capacity is available in 'n' places.

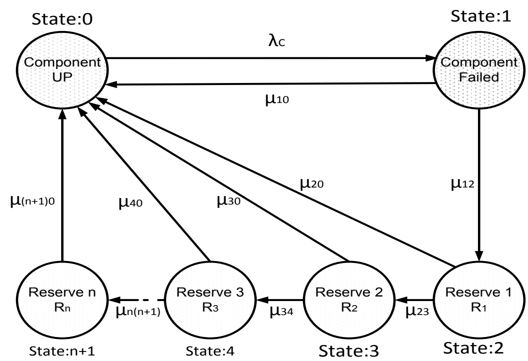

Fig. 5.2. Basic system model for HV/MV transformer fault.

State 0: Up state denotes a working transformer.

State 1: Fail state shows the faulty transformer in the system. The load connected to the faulty transformer will be out of supply in this state. If the system does not contain reserve transformer capacity then the transition from here to the up state requires repair time.

State 2: It is the first reserve state in which supply to the disconnected load is restored. The transition to this state depends on first reserve transformer switching time. If capacity of this reserve transformer is sufficient to supply the entire disconnected demand then system remains in this state until repair is accomplished. Otherwise, partial load will remain unsupplied in this state; therefore, transition to next reserve is needed.

State 3: It is a second reserve state in which supply to un-energized load of state 2 is connected. Transition rate from state '2' to state '3' is proportional to the second reserve transformer switching time. The next reserve state is only visited if even second reserve is not adequate for the load.

Similarly, State '4' and 'n+1' are the third and last reserve state, respectively.

The transition rates μ_{uv} between states are a function of transition time, the number of reserves available, and the amount of load disconnected. These rates are conditional. The number of reserves and load disconnected determine either rate is zero or a certain value.

C) HV busbars:

The configuration of HV busbars can be among single bus, sectionalized single bus, breaker-and-a-half, double breaker-double bus, and ring bus [113] [114]. The configuration determines the design of the model for busbars. Model for the single or sectionalized single bus are similar to that of HV/MV transformers, whereas, other configurations follow the model of HV lines.

Proposed Modified Models: With DR

The decrease in load due to DR depends on DR capacity, demand postponement time, load at load point, and duration for which load is higher than capacity. The mathematical expression is shown below.

$$L_{DR} = \begin{cases} C_{DR} \times L & \text{If } t_{req} \le T_{DR} \\ C_{DR} \times L \times T_{DR} / t_{req} & \text{else} \end{cases} \tag{64}$$

Where,

L_{DR} is decrease in load due to demand response.

C_{DR} denotes demand response capacity of load (in %).

L is load demand in kW.

T_{DR} represents demand deferment time without interruption cost (h/day).

t_{req} is time for which load is higher than capacity (h).

Equation (64) indicates that if t_{req} is less than or equal to the demand postponement time then the entire DR resource can be used at same time. Otherwise, DR resources are activated sequentially in form of groups to make sure load demand is reduced for the required duration.

Following are the modified models incorporating DR.

A) HV lines:

Fig. 5.3 displays the modified model for an HV (Sub-transmission) lines fault.

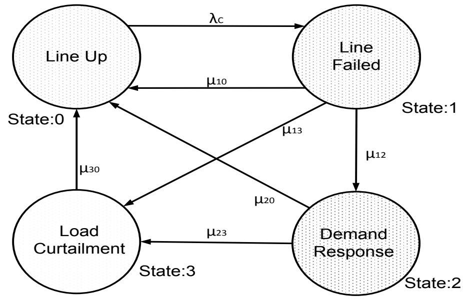

Fig. 5.3. Modified system model for HV line fault.

State 0: Up state denotes that all the line sections are working.

State 1: Failed state shows that one of the sub-transmission segments is in a failed state, before load curtailment or DR activation. A remaining network capacity enough to supply the entire load keeps the system in this state until repair is complete. Otherwise, the network can be loaded up to short-term emergency loading capacity in this state before transition to next state.

State 2: DR state is reached from state '1' in case DR action reduces the LC requirement. If LC is not required post DR activation then system will move to state '0' by completion of repair, otherwise, state '3' will be visited.

State 3: This is load curtailment state that can be reached from state '2' or directly from state '1'. The direct transition from state '1' to '3' occurs in case DR does not reduce LC requirement. After repair, the up state is always reached from here.

The transition rates for various states are given in the following equations that are self-explanatory.

$$\mu_{10} = \begin{cases} 1/T_r & \text{If LC and DR not required.} \\ 0 & \text{else} \end{cases} \tag{65}$$

$$\mu_{12} = \begin{cases} 1/t_{DR} & \text{If DR reduces LC.} \\ 0 & \text{else} \end{cases} \tag{66}$$

$$\mu_{20} = \begin{cases} 1/(\mathrm{T}_r - t_{DR}) & \text{If LC not needed after DR.} \\ 0 & \text{else} \end{cases} \tag{67}$$

$$\mu_{13} = \begin{cases} 1/T_{LC} & \text{If DR doesn't reduce LC.} \\ 0 & \text{else} \end{cases} \tag{68}$$

$$\mu_{23} = \begin{cases} 1/T_{LC} & \text{If LC needed after DR.} \\ 0 & \text{else} \end{cases} \tag{69}$$

$$\mu_{30} = \begin{cases} 1/(\mathrm{T}_r - T_{LC}) & \text{If } DR \text{ doesn't reduce LC.} \\ 1/(\mathrm{T}_r - T_{LC} - t_{DR}) & \text{else} \end{cases} \quad (70)$$

Where,

μ_{uv} represents transition rate from state u to v.

T_r is time required to repair and re-connect component (including detection and isolation).

t_{DR} denotes DR activation time.

T_{LC} is load curtailment time.

B) HV/MV transformer:

For simplicity, it is assumed that the reserve capacity for a transformer may be available in two other transformers, one in same substation and the other in a NSS. Fig. 5.4 shows the modified system model for an HV/MV transformer contingency.

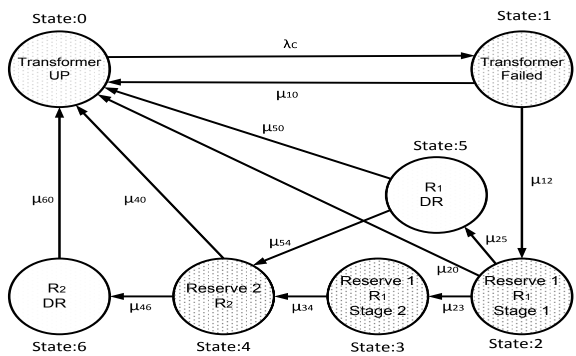

Fig. 5.4. Modified system model for HV/MV transformer fault.

State 0: Up state represents working transformer.

State 1: Fail state designates a faulty transformer. If reserve and DR are not present then system will persist in this state up till completion of the repair.

$$\mu_{10} = \begin{cases} 1/T_r & \text{If DR and reserve not available.} \\ 0 & \text{else} \end{cases} \quad (71)$$

State 2: Stage 1 of the first reserve state. After breaker switching time, disconnected feeders are connected to the reserve transformer in the same substation. It is ensured that transformer short-term emergency rating limit is complied. Transition to further reserve or DR state is needed only in case the long-term emergency capacity of the first reserve transformer is not enough to accept the entire load.

$$\mu_{12} = 1/t_{CB} \tag{72}$$

$$\mu_{20} = \begin{cases} 1/(\mathrm{T}_r - t_{CB}) & \text{If DR \& LC not needed } (\mathrm{R}_1). \\ 0 & \text{else} \end{cases} \tag{73}$$

Where,

t_{CB} denotes circuit breaker switching time, including fault detection.

R_1 represents reserve state 1.

State 3: Stage 2 of the first reserve state. If DR is not able to reduce LC required quantity of first stage in reserve 1 then after load curtailment time this state is visited. In this state, transformer is not loaded more than long-term emergency load rating. As load is disconnected partially in this state, therefore, the passing to second reserve state will always happen.

$$\mu_{23} = \begin{cases} 1/\mathrm{T}_{LC} & \text{If DR not but LC needed } (\mathrm{R}_1). \\ 0 & \text{else} \end{cases} \tag{74}$$

State 5: The first reserve with demand response state is succeeded if DR activation is able to reduce LC in reserve 1. Here, the transformer long-term emergency load rating is not violated. If DR eradicates the LC need, then after DR activation time state '5' is visited and state '0' is attained after completion of repair. Otherwise, this transition (from state '2' to state '5') needs sum of DR activation and load curtailment time; and state '4' is visited after it.

$$\mu_{25} = \begin{cases} 1/t_{DR} & \text{If DR needed but not LC } (\mathrm{R}_1). \\ 1/(\mathrm{T}_{LC} + t_{DR}) & \text{If DR and LC needed } (\mathrm{R}_1). \\ 0 & \text{else} \end{cases} \tag{75}$$

$$\mu_{50} = \begin{cases} 1/(\mathrm{T}_r - t_{CB} - t_{DR}) & \text{If DR eliminates LC.} \\ 0 & \text{else} \end{cases} \tag{76}$$

State 4: This is the second reserve state that corresponds to the transformer in a neighboring substation. The power to load is connected here that was un-energized in reserve 1. This state is achieved after network re-arrangement time either from state '3' or from state '5'. If the long-term emergency capacity of the second reserve transformer is adequate to supply the balance load or DR activation does not decrease LC requirement in reserve 2, then system will persist in this state till repair of fault. If DR activation is also needed, then short-term emergency loading can be applied on this transformer as well.

$$\mu_{34} = 1/h_{sw} \tag{77}$$

$$\mu_{54} = \begin{cases} 1/h_{sw} & \text{If DR and LC needed } (\mathrm{R}_1). \\ 0 & \text{else} \end{cases} \tag{78}$$

$$t_4 = h_{sw} + T_{LC} + t_{CB} \tag{79}$$

$$\mu_{40} = \begin{cases} 1/(\mathrm{T}_r - t_4) & \text{If DR not needed } (\mathrm{R}_1 \text{ and } \mathrm{R}_2). \\ 1/(\mathrm{T}_r - t_4 - t_{DR}) & \begin{array}{c}\text{If DR needed } (\mathrm{R}_1) \text{ and} \\ \text{DR not needed } (\mathrm{R}_2).\end{array} \\ 0 & \text{else} \end{cases} \quad (80)$$

Where,

h_{sw} is time required to transfer load to a neighboring substation.

R_2 represents reserve state 2.

t_4 is time required to reach state '4' from state '1' through state '3'.

State 6: The second reserve with DR state. This state is reached from state '4' if DR activation is able to decrease LC in reserve 2. From here, transition will always be towards the up state.

$$\mu_{46} = \begin{cases} 1/t_{DR} & \text{If DR needed } (\mathrm{R}_2). \\ 0 & \text{else} \end{cases} \quad (81)$$

$$\mu_{60} = \begin{cases} 1/(\mathrm{T}_r - t_4 - t_{DR}) & \text{If DR not needed } (\mathrm{R}_1). \\ 1/(\mathrm{T}_r - t_4 - 2t_{DR}) & \text{else} \end{cases} \quad (82)$$

C) HV busbars:

Depending on configuration, HV busbar contingency models are similar to the ones presented for lines and transformers.

5.3 Outage Cost Evaluation Framework

Fig. 5.5 shows the flow diagram for computing the outage costs of an HV network that contains the following eight modules.

- Module 1: The first step is to obtain data related to the network. The data may include the information of electrical components type, rating, interconnection, fault rates, repair time, operation procedures, network configuration, and load point.
- Module 2: This module initializes the hour counter h which is used to consider the likely contingencies at each hour of the year.
- Module 3: Contingency counter c is initialized in this block. It is needed in order to compute total outage cost due to all the contingencies.
- Module 4: This module determines the amount of load to be disconnected due to a contingency, before and after the activation of DR or switching to the reserve. This block is re-examined until all contingencies have been reflected.
- Module 5: The model for all the network contingencies at hour h is created in this module. This model is a combination of system state models for each contingency designed in preceding section.

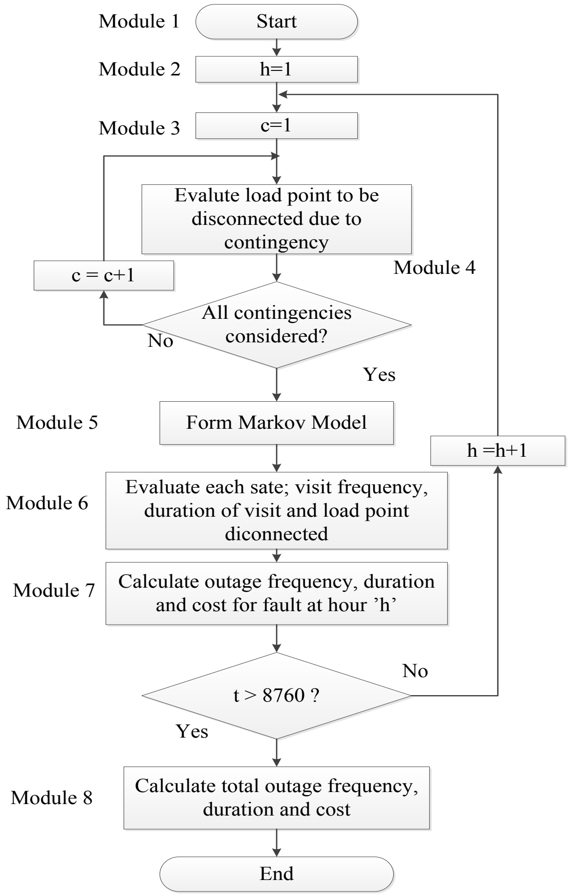

Fig. 5.5. Flow diagram for calculating the outage costs due to HV faults.

Mathematically, the Markov model is presented as an $'r+1\times r+1'$ transition rate matrix (83) and steady state probability of system of a state is calculated solving (84) - (86).

$$TM = \begin{bmatrix} a_{00} & a_{01} & \cdots & a_{0r} \\ a_{10} & a_{11} & \cdots & a_{1r} \\ \vdots & \vdots & \ddots & \vdots \\ a_{r0} & a_{r1} & \cdots & a_{rr} \end{bmatrix} \qquad (83)\ [111]$$

$$P \cdot TM = 0 \qquad (84)\ [111]$$

$$\sum_{u=0}^{r} P_u = 1 \qquad (85)\ [111]$$

$$P = \begin{bmatrix} P_0 & P_1 & \cdots & P_r \end{bmatrix} \qquad (86)\ [111]$$

Where,

TM is transition rate matrix.

$a_{uv}\ \forall\ u \neq v$ represents transition rate from state u to state v (a_{uu} is such that the sum of all the elements in a row is zero).

$r+1$ is equal to number of states in the model.

P represents probability matrix.

P_u denotes steady state probability of system in state u.

- Module 6: This module determines the visit frequency and the mean durations of visit of each state using (87) and (88). Load points disconnected in each state are also calculated in here.

$$\omega_v = \sum_{s=0, s\neq v}^{r} P_s a_{sv} \qquad (87)\ [111]$$

$$\psi_v = P_v / \omega_v \qquad (88)\ [111]$$

Where,

s, v are the indices of the states.

ω_v represents the visit frequency of state v.

ψ_v denotes the visit duration of state v.

- Module 7: In this module, the outage cost for faults at each hour is calculated by (89).

$$ECOST_h = \sum_u \sum_x \left\{ \begin{array}{l} OP_x^u \cdot (OF_x^u \cdot CIC_1 \\ +OD_x^u \cdot CIC_2) \end{array} \right\} \qquad (89)$$

Where,

x is load point index.

OP_x^u is outage power (kW) at load point x in state u.

OF_x^u is outage frequency of load point x in state u. Its value is ω_u if load is disconnected, zero otherwise. For a particular contingency it is considered only once.

$OD_x^u = \psi_u$ is outage duration (h) of load point x in state u, if load is disconnected in that state.

CIC_1 is customer interruption cost parameter related to frequency of interruptions (€/kW/fault).

CIC_2 is customer interruption cost parameter related to duration of interruptions (€/kWh).

$ECOST_h$ is the expected outage cost considering faults at hour h. It is the sum of the outage costs in all states, at all load points.

The steps from module 3 to module 7 are reiterated 8760 times to a cover a full year.

-Module 8: The results of prior modules are summed to calculate annual expected outage cost for the entire network.

$$ECOST = \sum_{h=1}^{8760} ECOST_h \qquad (90)$$

Where,

$ECOST$ is the expected annual outage cost for the entire network.

5.4 Case Studies and Results

A typical Finnish sub-transmission (110kV) network, as drawn in Fig. 5.6, is considered as the test system (detailed information related to test system can be found in [VI]). The network consists of 12 line segments supplying power to two primary substations; namely SS1 and SS2. Each substation connects MV feeders of load via two primary transformers (110/20kV). A normally open back-up connection between substations is also available to provide support during contingencies. SS1 contains transformers T1 and T2 that supply power to a commercial area where consumers are office, shops, and district/oil heated houses. As displayed in Fig. 5.7a, load peaks are wider at this substation and difference between summer and winter load is small. SS2 comprises of transformers T3 and T4 that supply power to an area where consumers are combination two types of houses, with electric and district/oil heating. Demand peaks are narrow at this substation and difference between summer and winter load is significant, Fig. 5.7b. The present peak load at each substation, average load at SS1, and average load at SS2 are 38 MW, 19 MW, and 15 MW, respectively.

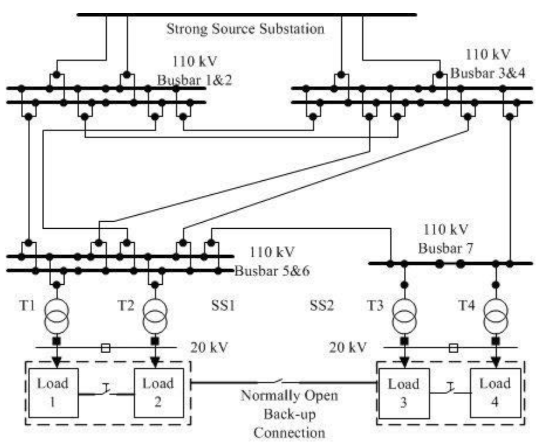

Fig. 5.6. Single-line diagram of typical Finnish sub-transmission network.

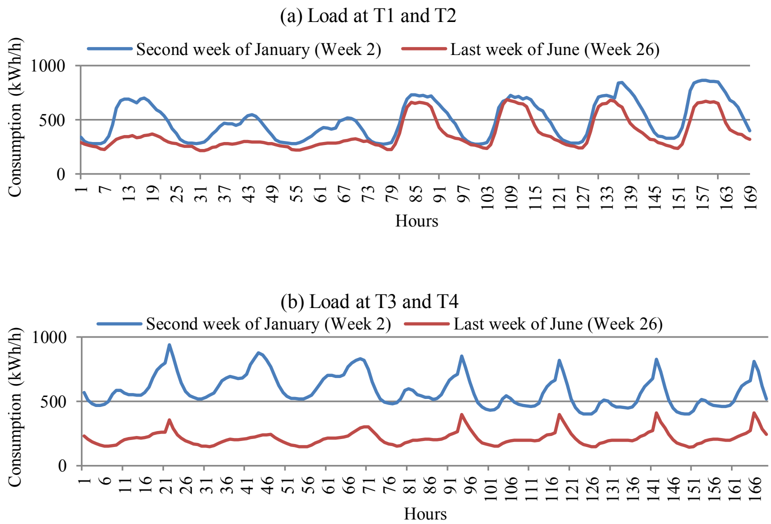

Fig. 5.7. Load profile of specific weeks at (a) SS1 and (b) SS2.

Fig. 5.8 demonstrates the DR capacity available at evening peak and at night for SS1 and SS2. In the evening (6pm), 30% load can be postponed for 15min or up to 7% load can be postponed for 300min, at SS1. For longer time only few loads can provide DR or load is decreased by curtailing load in small groups. At the same substation, DR potential at night (1am) is low due to less activity of consumers. As shown in Fig. 5.8b, in the evening (6pm), 41% load can be delayed for 15min or up to 11% load can be postponed for 300min at SS2. At this substation, DR potential at night (1am) is higher due to action of storage heaters. DR capacity at SS1 is lower than at SS2 because SS1 area is district/oil heated, whereas, in SS2 area around half of houses are electrically heated. Based on width of near peak load, optimal DR values are used in the case study; 7% demand postponement for 5h at SS1 and 17% demand delay for 3h at SS1.

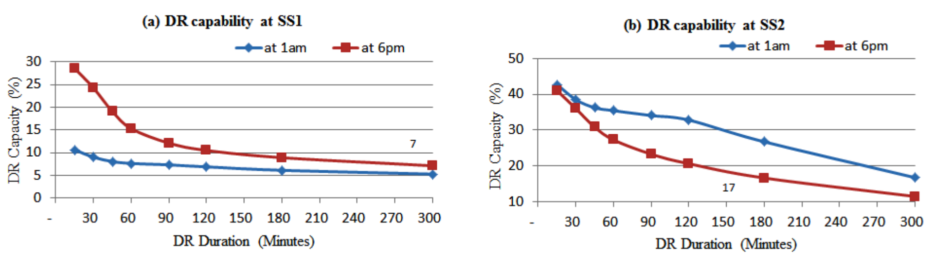

Fig. 5.8. DR capacity available at (a) SS1 and (b) SS2

Simulations are performed for the following case studies assuming scenarios of load growth up to 25%.

- Case1: In this base case, the network capacities are unchanged.
- Case2: This ideal case assumes that the network capacities are proportionally increased along with load growth.
- Case3: Functional DR is considered in this case, while keeping network capacities same as of Case 1.

Table 5–I lists the outage cost due to network contingencies for the above defined cases. At present, outage cost is same for all the cases because capacity shortage is not observed. Low outage cost in this scenario results from time required to connect reserve connection following contingencies at transformers and busbar 7.

TABLE 5-I
EXPECTED ANNUAL OUTAGE COST FOR CASE STUDIES.

Load Growth	ECOST			
	Case 1 [p]	Case 2[q]	Case 3 [g]	Reduction [p-g]/ [p-q]
(%)	(€/a)	(€/a)	(€/a)	(%)
Present	822	822	822	-
5	7 195	863	863	100
10	45 315	904	4 497	92
15	132 874	945	35 435	74
20	283 070	986	107 021	62
25	507 941	1 027	225 705	56

Case 1: Base Case

For increased load without upgrading network, contingencies near peak demand (in winter) result into capacity deficiency. The cost is higher for higher load growth. The outage cost in this case is due to following reasons:

- Load is required to be shed during HV line contingencies near peak load.
- Certain time is needed to transfer the load to the neighboring substation during contingencies of transformers and busbar 7 because reserve in same substation can only accept partial load.

Fig. 5.9 displays the share of each substation and each contingency type towards the outage cost. The portion of SS1 is higher owing to its wider near peak load and higher average load, Fig 5.9a. The highest share of HV line contingencies (Fig. 5.9b) is caused by lack of reserve during line faults. The presence of reserves for transformers and busbars make their share lower in the outage cost.

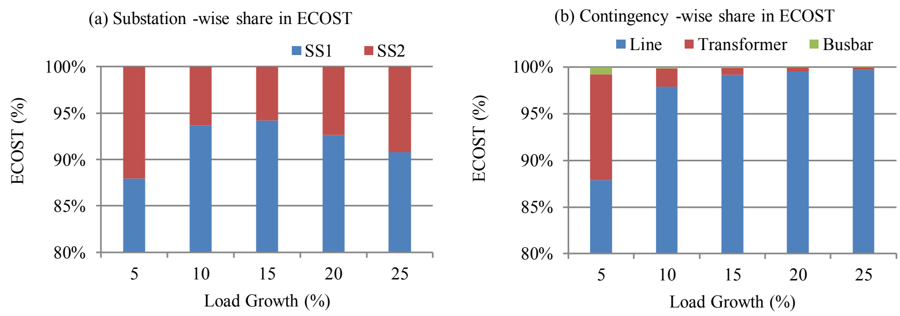

Fig. 5.9. The share in outage cost (case1) (a) substation-wise and (b) contingency type wise.

Case 2: Ideal Case

The interruption frequency and duration of the load does not change in case capacity of the components is consistently increased along with the load growth. However, small increase in outage cost compared to present value is caused by higher load values.

Case 3: Demand Response Case

In this case, DR activation after detecting a capacity shortage reduces or eliminates the load curtailment need. Fig. 5.10 depicts the decrease in outage cost at each substation. For 5% load growth, sufficient DR at both substations reduces the load during contingencies such that outage cost is identical to that of the ideal case. For load growth of 10% or more, DR capacity at SS1 (7%) is not adequate to remove capacity deficiency during near peak contingencies. Sufficient DR capacity at SS2 (17%) can handle contingencies in load growth scenarios of 10% and 15%, which is demonstrated by 100% *ECOST* decrease at SS2. Even for higher load growth, the reduction in outage cost at this substation is above 90%. This high decrease in outage cost at SS2 is due to certain load shape, with narrow winter peaks and high DR capacity. The investigation of substation-wise results indicates that higher DR capacity available at SS2 is able to manage higher capacity shortages during contingencies, while lower DR capacity available at SS1 is able to compensate lower load growth capacity deficiencies. The overall drop in outage cost is dominated by SS1 because of its high average load.

Fig. 5.11 exhibits the results of contingency wise outage cost reduction. The decrease in cost for transformer contingency is higher compared to line contingencies thanks to shorter duration (load transfer to the neighboring substation) for which DR activation is only needed.

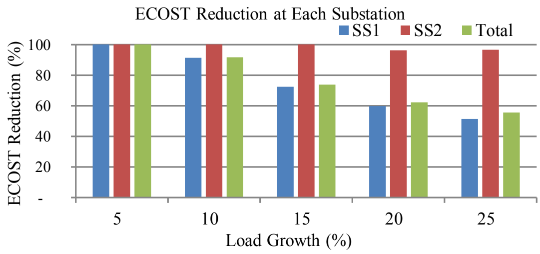

Fig. 5.10. Percentage reduction in expected annual outage cost at each substation (case 3).

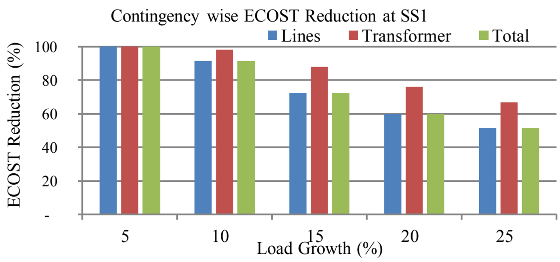

Fig. 5.11. Contingency wise reduction in expected annual outage cost at substation 1 (case 3).

The following inferences can be drawn from the results of case studies:

- DR is able to mitigate the redundancy capacity requirements of components proportional to its capability.
- DR benefits at a substation depend upon its load shape and DR capability.
- DR benefit also depends on the contingency type.

5.5 Conclusion

This chapter investigated the prospect of DR as a network redundancy alternative. The novel reliability models developed were used to estimate the outage cost for the comparative study. The case study results for a typical Finnish system indicated that redundant capacity of network components proportional to DR ability can be mitigated. The benefit of DR depends on the contingency type. Moreover, near peak load shape and DR capability influence the results. The utilities can use such an investigation to decide about the DR employments in order to obtain the benefits of network efficiencies improvements and delayed/avoided investments.

6 Conclusions and Future Works

6.1 Conclusions

The high utilization efficiency and the adequate capacity of high voltage (HV) systems are crucial elements for a reliable and an economical delivery of power supply. Novel solutions are required to deal with load growth, aging infrastructure, and high reliability needs in combination with low load factors of the demand. The main objective of this dissertation was to assess the potential benefits of demand response (DR) for capacity utilization improvement and lifesavings for the major assets of HV distribution system. The HV components considered in this study were HV/MV transformers, HV line/cables, and busbars. The transformers were given a particular importance due to their significant individual cost and critical position in the system.

The dissertation objective was divided into three key tasks that were presented in separate chapters. The first task, Chapter 3, focused on the capacity and lifesaving benefits of DR for transformers during operational stages. This task was further divided into three subtasks. In the first subtask, an optimization model was developed for utilization improvement of transformers using DR during normal operations without considering contingencies. The second subtask proposed static rating limit based DR optimization model for operational life extension and efficient capacity utilization of transformers during contingencies. The third subtask offered a hottest-spot-temperature (HST) based optimization model by which efficient utilization of transformers and lifesaving benefits can be achieved irrespective of ambient conditions. In the proposed models, DR was optimally activated to obtain the intended benefits. For each model, simulations were performed for typical Finnish systems' case studies. The results of the case studies indicated that substantial benefits in terms of lifesaving and capacity utilization improvement can be gained by employing DR in both normal and contingency operations. The cost of these benefits would be minimal only if load modifying decisions are optimally selected. These models/assessments can be used by utilities before making any real implementations of DR.

The second task, Chapter 4, dealt the problem of optimal capacity planning of power transformers in primary substations over long-run. This task was also further divided into two subtasks. In the first subtask, an optimization tool was devised for capacity planning of transformers (without considering DR) in which all the costs related to transformers, their failure rate increase with age, and their salvage value based on loss-of-life (LOL) were appropriately incorporated. In the second subtask, this tool was modified to include the features of DR and type of available load transfer switches (i.e. manual or remote) for load transfer between neighboring substations (NSS). In order to showcase the application of the developed tools, case studies and sensitivity analyses were presented for planning of a typical Finnish two-transformer substation capacity in various situations faced by utilities. The numerical results indicated the worth of the tools. The investigation revealed that the DR offers significant benefits in transformer capacity planning and these benefits are superior for systems in which remote switches are installed for load transfer between substations. The utilities can utilize these tools for planning of transformer ratings, their replacement and maintenance scheduling, and decisions of DR deployments.

Third task, Chapter 5, assessed the possibility of reserve capacity mitigation of HV network components (lines/cables. Transformers, and busbars) using DR as a redundancy resource activated by contingencies. This assessment was made by comparing outage cost of network contingencies with and without considering DR. In order to find the outage cost, novel Markov models were developed that imitate the various system states during faults. The case study results for a typical Finnish system showed that the redundant capacity of network components proportional to DR capability can be mitigated. The benefits of the DR depend upon the load shape as well as the contingency type. This assessment is useful for DR realization decisions in order to obtain the network efficiency improvement and delay/avoid investments.

6.2 Future works

There are several exciting research directions directly emerging from this dissertation, some of which are introduced in the below.

- Higher proliferation of distributed generations is contemplated in coming years that need different set of asset planning and management strategies. The models of this dissertation can be modified to incorporate the impact of distributed generations.
- High penetration of electric vehicles (EV) is anticipated in the future and its integration is an active field of research. EV poses challenges of peak load and also provides opportunities of DR and storage. This analysis can be extended to integrate the impact of EV on various levels of the distribution system.
- The availability of flexible loads for response depends on customers’ acceptance. Also, some level of customer comfort is compromised with these interruptions. In future, the analysis may be improved by considering the uncertainties associated with the flexible loads.

- Besides capacity and lifesaving gains evaluated in this dissertation, DR also offers other advantages to various players of the power system industry. The optimal division of DR among different players/benefits can be an interesting work in the future.
- This dissertation assessed the potential benefits of DR for HV system for capacity utilization improvement and lifesaving. Despite that this study was essential for obtaining the DR benefits, still its realization in practical systems needs enabling tools and strategies. The development of the enabling tools and strategies can be an interesting research direction.

References

[1] R. E. Brown and B. G. Humphrey, "Asset management for transmission and distribution," *IEEE Power Energy Mag.,* vol. 3, no. 3, pp. 39-45, May 2005.

[2] H. L. Willis, Power Distribution Planning Reference Book, Boca Raton, FL, Canada: CRC, 2010.

[3] S. Chu, ”Investing in our energy future,” *Grid Week Talk,* Sep. 2009.

[4] G. Strbac, "Demand side management: benefits and challenges," *Energy Policy,* vol. 36, no. 12, pp. 4419-4426, Dec. 2008.

[5] T. D. Poyser, "An on-line microprocessor based transformer analysis system to improve the availability and utilization of power transformers," *IEEE Trans. Power App. Syst.,* Vols. PAS-102, no. 4, pp. 957-962, Apr. 1983.

[6] D. A. Douglass, D. C. Lawry, A. A. Edris and E. C. Bascom, "Dynamic thermal ratings realize circuit load limits," *IEEE Comput. Appl. Power,* vol. 13, no. 1, pp. 38-44, Jan. 2000.

[7] B. Shahbazi and M. Vadiati, "Transformer condition monitoring system for smart grid," in *ICCIA*, 2011.

[8] S. Heidari, M. Fotuhi-Firuzabad and S. Kazemi, "Power distribution network expansion planning considering distribution automation," *IEEE Trans. Power Syst.,* in press.

[9] M. F. Shaaban, Y. M. Atwa and E. F. El-Saadany, "DG allocation for benefit maximization in distribution networks," *IEEE Trans. Power Syst.,* vol. 28, no. 2, pp. 639-649, May 2013.

[10] L. Fengji, Z. Junhua, Q. Jing, J. Foster, P. Yaoyao and D. Z. Yang, "Assessing the transmission expansion cost with distributed generation: an australian case study," *IEEE Trans. Smart Grid,* vol. 5, no. 4, pp. 1892-1904, Jul. 2014.

[11] A. Safdarian, M. Z. Degefa, M. Fotuhi-Firuzabad and M. Lehtonen, "Benefits of real-time monitoring to distribution systems: dynamic thermal rating," *IEEE Trans. Smart Grid,* in press.

[12] H. Endow and M. Triplett, "Demand response — the maturity cycle," in *IEEE ISGT Asia*, 2013.

[13] U. S. Department of Energy, "Benefits of demand response in electricity markets and recommendations for achieving them," Feb. 2006.

[14] FERC, "Assessment of demand response and advanced metering," Staff Rep. AD06-2-000, Aug. 2006.

[15] [Online]. Available: https://www4.helen.fi/Sahkokauppa/MakeContract.aspx. [Accessed 26 May 2015].

[16] G. Barbose, C. Goldman and B. Neenan, "A survey of utility experience with real time pricing," LBNL-54238, 2004.

[17] FERC, "A national assessment of demand response potential," Jun. 2009.

[18] O. Siddiqui, "Assessment of achievable potential from energy efficiency and demand

response programs in the US (2010-2030)," EPRI, Report No. 1016987, Palo Alto, CA, Jan. 2009.

[19] K. Samarakoon, J. Ekanayake and N. Jenkins, "Reporting available demand response," *IEEE Trans. Smart Grid,* vol. 4, no. 4, pp. 1842-1851, Dec. 2013.

[20] Elkraft, ”Demand Response - In Practice,” Newsletter published in connection with the conference "Enhancing and Developing Demand Response in the Energy Markets", Copenhagen, 2005.

[21] S. Kärkkäinen, "Demand response activities in Finland," DR Workshop, Copenhagen, Nov. 2006.

[22] S. Gyamfi, Demand Response Assessment and Modelling of Peak Electricity Demand in the Residential Sector: Information and Communication Requirements, Ph.D. dissertation, University of Canterbury, New Zealand, 2010.

[23] H. Asano, M. Takahashi and N. Ymaguchi, "Market potential and development of automated demand response system," in *IEEE PES General Meeting*, Jul. 2011.

[24] C. S. Chen and J. T. Leu, "Interruptible load control for Taiwan power company," *IEEE Trans. Power Syst.,* vol. 5, no. 2, pp. 460-465, May 1990.

[25] H. Saele and O. Grande, "Demand response from household customers: experiences from a pilot study in Norway," *IEEE Trans. Smart Grid,* vol. 2, no. 1, pp. 102-109, Mar. 2011.

[26] M. Ali, A. Safdarian and M. Lehtonen, "Demand response potential of residential HVAC loads considering users preferences," in *IEEE ISGT Europe*, Oct. 2014.

[27] R. Stamminger, G. Broil, C. Pakula, H. Jungbecker, M. Braun, I. Rudenauer and C. Wendker, "Synergy potential of smart appliances; D2.3 of WP 2 from the Smart-A project," 2008.

[28] M. Presutto, et al., "Preparatory studies for eco-design requirements of EuPs (Tender TREN/D1/40-2005) LOT 14: Domestic washing machines and dish washers," Dec. 2007.

[29] T. Lui, W. Stirling and H. O. Marcy, "Get smart," *IEEE Power Energy Mag.,* vol. 8, no. 3, pp. 66-78, May 2010.

[30] M. Z. Degefa, Energy Efficiency Analysis of Residential Electric End-Uses: Based on Statistical Survey and Hourly Metered Data, Masters thesis, School of Electrical Engineering, Aalto University, Finland, 2010.

[31] A. Safdarian, M. Fotuhi-Firuzabad and M. Lehtonen, "Benefits of demand response on operation of distribution networks: A case study," *IEEE Syst. J.,* in press.

[32] A. H. Mohsenian-Rad and A. Leon-Garcia, "Optimal residential load control with price prediction in real-time electricity pricing environments," *IEEE Trans. Smart Grid,* vol. 1, no. 2, pp. 120-133, Sep. 2010.

[33] D. S. Kirschen, "Factoring the elasticity of demand in electricity prices," *IEEE Trans. Power Syst.,* vol. 15, no. 2, pp. 612-617, May 2000.

[34] E. A. M. Cesena and P. Mancarella, "Distribution network reinforcement planning considering demand response support," in *Power Systems Computation Conference (PSCC)*, Aug. 2014.

[35] P. Bjerregaard, I. Szczesny, I. de Cerio Mendaza and J. Pillai, "Intelligent control of flexible loads for improving low voltage grids utilization," in *IEEE PES ISGT Europe*, Oct. 2013.

[36] C. L. Su and D. Kirschen, "Quantifying the effect of demand response on electricity markets," *IEEE Trans. Power Syst.,* vol. 24, no. 3, pp. 1199-1207, Aug. 2009.

[37] D. Krischen, "Demand-side view of electricity markets," *IEEE Trans. Power Syst.,* vol. 18, no. 2, p. 520–527, May 2003.

[38] K. Singh, N. P. Padhy and J. Sharma, "Influence of price responsive demand shifting bidding on congestion and LMP in pool-based day-ahead electricity markets," *IEEE Trans. Power Syst.,* vol. 26, no. 2, pp. 886-896, May 2011.

[39] W. Yunfei, I. R. Pordanjani and X. Wilsun, "An event-driven demand response scheme for power system security enhancement," *IEEE Trans. Smart Grid,* vol. 2, no. 1, pp. 23-29, Mar. 2011.

[40] S. A. Pourmousavi and M. H. Nehrir, "Introducing dynamic demand response in the LFC model," *IEEE Trans. Power Syst.,* in press.

[41] J. H. E. e. al., "Innovative developments in load as a reliability resource," in *IEEE PES Winter Meeting*, 2002.

[42] A. Safdarian, M. Z. Degefa, M. Lehtonen and M. Fotuhi-Firuzabad, "Distribution network reliability improvements in presence of demand response," *IET Gen. Trans. Dist.,* vol. 8, no. 12, pp. 2027 - 2035, Dec. 2014.

[43] W. Hongyu, M. Shahidehpour and A. Al-Abdulwahab, "Hourly demand response in day-ahead scheduling for managing the variability of renewable energy," *IET Gen. Trans. Dist.,* vol. 7, no. 3, pp. 226-234, Mar. 2013.

[44] S. Holland and E. Mansur, "Is real-time pricing green? The environmental impacts of electricity demand variance," *Rev. Econ. Stat,* vol. 90, no. 3, p. 550–561, 2008.

[45] S. M. Madaeni and R. Sioshansi, "Using demand response to improve the emission benefits of wind," *IEEE Trans. Power Syst.,* vol. 28, no. 2, pp. 1385-1394, May 2013.

[46] P. Van Dievel, K. De Vos, R. Belmans and K. De Vos, "Demand response in electricity distribution grids: Regulatory framework and barriers," in *11th International Conference on the European Energy Market (EEM)*, May 2014.

[47] M. Zimmerman, "The industry demands better demand response," in *IEEE PES ISGT*, Washington, DC, Jan. 2012.

[48] "IEEE guide for loading mineral-oil-immersed transformers and step-voltage regulators," IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995), Jul. 2012.

[49] "Powe transformers part 7: loading guide for oil-immersed power transformers," International standard IEC 60076-7, 2005.

[50] S. M. M. Agah and H. A. Abyaneh, "Distribution transformer loss-of-life reduction by increasing penetration of distributed generation," *IEEE Trans. Power Del.,* vol. 26, no. 2, pp. 1128-1136, Apr. 2011.

[51] S. M. M. Agah and H. A. Abyaneh, "Quantification of the distribution transformer life extension value of distributed generation," *IEEE Trans. Power Del.,* vol. 26, no. 3, pp. 1820-1828, Jul. 2011.

[52] M. D. Wilkinson and P. Dyer, "Continuous moisture management: extending transformer service life," in *CIRED*, 2001.

[53] N. Dominelli, A. Rao and P. Kundur, "Life extension and condition assessment: techniques for an aging utility infrastructure," *IEEE Power Energy Mag.,* vol. 4, no. 3, pp. 24-35, May 2006.

[54] H. Chappa, T. Thakur and B. Reddy, "Review on condition monitoring and life extension of transformer," in *IEEE Students' Conference on Electrical, Electronics and Computer Science (SCEECS)*, Mar. 2014.

[55] T. S. Jalal, N. Rashid and B. van Vliet, "Implementation of dynamic transformer rating in a distribution network," in *IEEE Int. Conf. Power Syst. Technol. (POWERCON)*, Auckland , Nov. 2012.

[56] A. D. Hilshey, P. D. H. Hines, P. Rezaei and J. R. Dowds, "Estimating the impact of electric vehicle smart charging on distribution transformer aging," *IEEE Trans. Smart Grid,* vol. 4, no. 2, pp. 905-913, Jun. 2013.

[57] H. Turker, S. Bacha, D. Chatroux and A. Hably, "Low-voltage transformer loss-of-life assessments for a high penetration of Plug-in Hybrid Electric Vehicles (PHEVS)," *IEEE Trans. Power Del.,* vol. 27, no. 3, pp. 1323-1331, Jul. 2012.

[58] S. Argade, V. Aravinthan and W. Jewell, "Probabilistic modeling of EV charging and its impact on distribution transformer loss of life," in *IEVC*, 2012.

[59] Q. Gong, S. Midlam-Mohler, V. Marano and G. Rizzoni, "Study of PEV charging on residential distribution transformer life," *IEEE Trans. Smart Grid,* vol. 3, no. 1, pp. 404-412, Mar. 2012.

[60] J. M. Sexauer, K. D. McBee and K. A. Bloch, "Applications of probability model to analyze the effects of electric vehicle chargers on distribution transformers," in *IEEE Electrical Power and Energy Conference (EPEC)*, Oct. 2011.

[61] S. Shao, M. Pipattanasomporn and S. Rahman, "Grid integration of electric vehicles and demand response with customer choice," *IEEE Trans. Smart Grid,* vol. 3, no. 1, pp. 543-550, Mar. 2012.

[62] S. Shao, M. Pipattanasomporn and S. Rahman, "Demand response as a load shaping tool in an intelligent grid with electric vehicles," *IEEE Trans. Smart Grid,* vol. 2, no. 4, pp. 624 - 631, Dec. 2011.

[63] C. Zhang, F. Wen, Y. Xue, G. Ledwich and J. Lei, "Impacts of plug-in electric vehicles on distribution networks," in *IEEE Conference on Power & Energy (IPEC)*, Dec. 2012.

[64] L. Dow, M. Marshall, L. Xu, J. R. Aguero and H. L. Willis, "A novel approach for evaluating the impact of electric vehicles on the power distribution system," in *IEEE PES General Meeting*, 2010.

[65] K. Qian, C. Zhou and Y. Yuan, "Impacts of high penetration level of fully electric vehicles charging loads on the thermal ageing of power transformers," *International Journal of Electrical Power & Energy Systems,* vol. 65, pp. 102-112, Feb. 2015.

[66] W. Khamphanchai, M. Pipattanasomporn, M. Kuzlu, J. Zhang and S. Rahman, "An approach for distribution transformer management with a multiagent system," *IEEE Trans. Smart Grid,* vol. 6, no. 3, pp. 1208-1218, May 2015.

[67] T. Ku, C. Chen, C. Lin and W. Shyu, "Design of an intelligent transformer management system," in *IEEE PES T&D Conference and Exposition*, Apr. 2014.

[68] J. Jargstorf, K. Vanthournout, T. De Rybel and D. Van Hertem, "Effect of demand response on transformer lifetime expectation," in *IEEE ISGT Europe*, 2012.

[69] M. Z. Degefa, R. J. Millar, M. Koivisto, M. Humayun and M. Lehtonen, "Load flow analysis framework for active distribution networks based on smart meter reading system," *Engineering,* vol. 5, no. 10A, pp. 1-8, 2013.

[70] "General Algebraic Modelling System," 2013. [Online]. Available: http://www.gams.com.

[71] D. Susa, J. Palola, M. Lehtonen and M. Hyvarinen, "Temperature rises in an OFAF transformer at OFAN cooling mode in service," *IEEE Trans. Power Del.,* vol. 20, no. 4, pp. 2517-2525, Oct. 2005.

[72] CIGRE WG A2.20, "Guide on economics of transformer management," Jun. 2004.

[73] S. Y. Merritt and S. D. Chaitkin, "No load versus load losses," *IEEE Ind. Appl. Mag.,* vol. 9, no. 6, pp. 21-28, Nov.-Dec. 2003.

[74] W. H. Bartley, "Life cycle management of utility transformer assets," in *Breakthrough Asset Management for the Restructured Power Industry Conf.*, Utah, Oct. 2002.

[75] Y. G. Bae, P. N. Adkins and D. W. Bree, "Quantitative evaluation of the cost and benefits associated with transformer loading," *IEEE Trans. Power App. Syst.,* Vols. PAS-98, no. 1, Jan. 1979.

[76] M. Gilvanejad, H. Ghadiri, M. R. Shariati and S. Khayyamim, "Analyzing the effect of transformer utilization factor in distribution networks as an investment management index by using DisPlan software," in *CIRED*, Jun. 2013.

[77] J. Ostergaard and A. N. Jensen, "Can we delay the replacement of this component?-An asset management approach to the question," in *CIRED*, 2001.

[78] J. Wang, P. M. S. Carvalho and J. L. Kirtley, "Improving transformers' utilization under single contingency policy and customer reliability requirements," *IEEE Trans. Smart Grid,* vol. 4, no. 4, pp. 2384-2391, Dec. 2013.

[79] L. C. Leung, S. K. Khator and J. Schnepp, "Planning substation capacity under the single contingency scenario," *IEEE Trans. Power Syst.,* vol. 10, no. 3, pp. 1442-1447, Aug. 1995.

[80] J. Hazra, K. Das, A. P. Kumar, B. Narayanaswamy, D. P. Seetharam and N. Jespersen, "Optimal utilization of power transformers through virtual sensing," in *IEEE ISGT Europe*, Oct. 2013.

[81] A. A. Chowdhury, L. Bertling and D. E. Custer, "Determining distribution substation transformer optimal loading using a reliability cost-benefit approach," in *PMAPS*, 2006.

[82] S. M. Mazhari, M. Monsef and R. Romero, "A hybrid heuristic and evolutionary algorithm for distribution substation planning," *IEEE Syst. J.,* in press.

[83] R. C. Lotero and J. Contreras, "Distribution system planning with Reliability," *IEEE Trans. Power Del.,* vol. 26, no. 4, pp. 2552-2562, Oct. 2011.

[84] T. Gonen and B. L. Foote, "Mathematical dynamic optimization model for electrical distribution system planning," *Elect. Power Energy Syst.,* vol. 4, no. 2, pp. 129-136, 1982.

[85] E. Masud, "An interactive procedure for sizing and timing distribution substations using optimal techniques," in *IEEE PES Winter Meeting*, 1974.

[86] C. W. 12.05, "An international survey on failures in large power transformers in service," *ELECTRA,* vol. 88, pp. 21-48, 1983.

[87] EC Directive 2003/54/EC, "EC Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003, concerning common rules for the internal market in electricity and repealing Directive 96/92/EC," *Official Journal of the European Union,* vol. L176, Jul. 2003.

[88] O. Siirto, A. Safdarian, M. Lehtonen and M. Fotuhi-Firuzabad, "Optimal distribution network automation considering earth fault events," *IEEE Trans. Smart Grid,* vol. 6, no. 2, pp. 1010-1018, Mar. 2015.

[89] A. Safdarian, M. Lehtonen, M. Fotuhi-Firuzabad and R. Billinton, "Customer interruption cost in smart grids," *IEEE Trans. Power Syst.,* vol. 29, no. 2, pp. 994-995, Mar. 2014.

[90] A. Zakariazadeh, S. Jadid and P. Siano, "Stochastic multi-objective operational planning of smart distribution systems considering demand response programs," *Electr. Pow. Syst. Res.,* vol. 111, pp. 156-168, Jun. 2014.

[91] H. Dange and R. Billinton, "Effects of load sector demand side management applications in generating capacity adequacy assessment," *IEEE Trans. Power Syst.,* vol. 27, no. 1, pp. 335-343, Feb. 2012.

[92] H. R. Arasteh and M. R. Haghifam, "Concurrent impacts of automation and demand response on utilities reliability costs in performance based regulation scheme," in *IEEE PES General Meeting*, Jul. 2012.

[93] A. K. Kazerooni and J. Mutale, "Transmission network planning under a price-based demand response program," in *IEEE PES T&D Conference and Exposition*, Apr. 2010.

[94] A. K. Kazerooni and J. Mutale, "Network investment planning for high penetration of wind energy under demand response program," in *PMAPS*, Jun. 2010.

[95] E. A. Martinez Cesena and P. Mancarella, "Economic assessment of distribution network reinforcement deferral through post-contingency demand response," in *IEEE ISGT Europe*, Oct. 2014.

[96] J. Palola, Dynamic Scenario Modelling in Electricity Distribution System Asset Management, Ph.D. dissertation, School of Electrical Engineering, Aalto University, Finland, 2014.

[97] H. P. Williams, Model Building in Mathematical Programming, 5th ed., New York: John Wiley, 2013.

[98] "Nordpool," [Online]. Available: http://www.nordpoolspot.com.

[99] S. Kazemi, Reliability Evaluation of Smart Distribution Grids, Ph.D. dissertation, School of Electrical Engineering, Aalto University, Finland, 2011.

[100] A. Silvast, P. Heine, M. Lehtonen, et al., "Costs of electricity supply outages report of power systems and high voltage engineering," Costs of electricity supply outages report of power systems and high voltage engineering, 2005. (in Finnish with English summary).

[101] R. Billinton and R. N. Allan, Reliability Evaluation of Engineering Systems: Concepts and Techniques, 2nd ed., New York: Springer, 1992.

[102] G. Chenghong and L. Furong, "Quantifying the long-term benefits of interruptible load scheme for distribution network investment," in *IEEE PES General Meeting*, Jul. 2011.

[103] R. Billinton and R. N. Allan, Reliability Evaluation of Power Systems, 2nd ed., New York: Plenum Press, 1996.

[104] R. J. Ringlee and S. D. Goode, "On procedures for reliability evaluations of transmission systems," *IEEE Trans. Power App. Syst.,* Vols. PAS-89, no. 4, pp. 527-536, Apr. 1970.

[105] J. Endrenyi, "Three-state models in power system reliability evaluations," *IEEE Trans. Power App. Syst.,* Vols. PAS-90, no. 4, pp. 1909-1916, Jul. 1971.

[106] J. Endrenyi, P. C. Maenhaut and L. E. Payne, "Reliability evaluation of transmission

systems with switching after faults approximations and a computer program," *IEEE Trans. Power App. Syst.,* Vols. PAS-92, no. 6, pp. 1863-1875, Nov. 1973.

[107] R. N. Allan, R. Billinton and M. F. De Oliveira, "Reliability evaluation of electrical systems with switching actions," *Proceedings of the Institution of Electrical Engineers,* vol. 123, no. 4, pp. 325-330, Apr. 1976.

[108] R. N. Allan, E. N. Dialynas and I. R. Homer, "Modelling and evaluating the reliability of distribution systems," *IEEE Trans. Power App. Syst.,* Vols. PAS-98, no. 6, pp. 2181-2189, Nov. 1979.

[109] R. Billinton, H. Chen and Z. Jiaqi, "Generalized N+2 state system markov model for station-oriented reliability evaluation," *IEEE Trans. Power App. Syst.,* vol. 12, no. 4, pp. 1511-1517, Nov. 1997.

[110] R. Billinton and H. Chen, "Weaknesses of the conventional three-state model in station-oriented reliability evaluation," *Microelectronics Reliability,* vol. 37, no. 12, pp. 1799-1804, Dec. 1997.

[111] M. Rausand and A. Hoyland, System Reliability Theory: Models, Statistical Methods, and Applications, 2nd ed., John Wiley & Sons, 2004.

[112] C. Singh and R. Billinton, "Closure to discussion of reliability modelling in systems with non-exponential down time distributions," *IEEE Trans. Power App. Syst.,* Vols. PAS-92, no. 2, pp. 790-800, Mar. 1973.

[113] USDA, "Design guide for rural substations," RUS Bulletin:1724E-300, Jun. 2001.

[114] [Online]. Available: http://askramadhan.wordpress.com/2009/03/22/busbar-configuration-in-single-line-diagram/. [Accessed Jun. 2015].

Aalto-DD 188/2015

ISBN 978-952-60-6519-9 (printed)
ISBN 978-952-60-6520-5 (pdf)
ISSN-L 1799-4934
ISSN 1799-4934 (printed)
ISSN 1799-4942 (pdf)

Aalto University
School of Electrical Engineering
Department of Electrical Engineering and Automation
www.aalto.fi

BUSINESS +
ECONOMY

ART +
DESIGN +
ARCHITECTURE

SCIENCE +
TECHNOLOGY

CROSSOVER

DOCTORAL
DISSERTATIONS